CALIFORNIA RPS INTEGRATION COST ANALYSIS-PHASE I: ONE YEAR ANALYSIS OF EXISTING RESOURCES

CONSULTANT REPORT

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California Renewables Portfolio Standard Renewable Generation Integration Cost Analysis

PHASE I: ONE YEAR ANALYSIS OF EXISTING RESOURCES

RESULTS AND RECOMMENDATIONS

FINAL REPORT • FINAL RELEASE

PREPARED FOR

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ABBREVIATIONS

ACE	Area Control Error
ADS	Automated Dispatch System
AGC	Automatic Generation Control
CaISO	California Independent System Operator
CEC	California Energy Commission
CPUC	California Public Utilities Commission
CPS	Control Performance Standard
ELCC	Effective Load Carrying Capability
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
Hz	Hertz
IOU	Investor Owned Utility
ISO	Independent System Operator
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
MW	Megawatt (unit of power)
MWh	Megawatt-hour (unit of energy)
NERC	North American Electric Reliability Council
NREL	National Renewable Energy Laboratory
ORNL	Oak Ridge National Laboratory
RPS	Renewables Portfolio Standard
RTO	Regional Transmission Organization
$/MW-hr	Dollars per Megawatt for one hour of capacity

NOMENCLATURE

ACE	*area control error*
β	*control area frequency bias*
C_i	*capacity available in hour i*
ΔC_i	*effective capacity of analyzed resource at hour i*
ΔC_p	*effective capacity of analyzed resource at peak hour of year*
$COST_{lf}$	*cost of supplemental energy*
$COST_R$	*cost of regulation*
F_A	*actual system frequency*
F_S	*scheduled system frequency*
G	*total actual system generation*
g_i	*generation of analyzed resource*
g_i	*generation of analyzed resource at hour I*
$\overline{g_{i,15}}$	*fifteen minute rolling average of generation of analyzed resource*
g_{i,s_1}	*hour-ahead generation forecast/schedule*
g_{i,s_2}	*short term generation forecast*
I_{ME}	*meter error*
i	*generic indicator of analyzed resource*
L	*total actual system load*
$\overline{L_{15}}$	*fifteen minute rolling average of system load*
L_i	*hourly system load*
L_{s_1}	*hour-ahead load forecast/schedule*
L_{s_2}	*short term load forecast/real-time load schedule*
$LOLE$	*loss of load probability*
$LOLE'$	*LOLE with resource of interest added to system*
lf_i	*supplemental energy requirement of analyzed resource*
lf_L	*supplemental energy requirement of load*
N	*number of hours in the year*
NI_A	*actual net tie flows of control area*
NI_S	*scheduled net tie flows of control area*
P	*probability function*

R_{actual}	*actual amounts of purchased/self provided regulation*
R_i	*regulation requirement of analyzed resource*
$\hat{R}_i$	*allocated regulation share of analyzed resource*
$RATE_{lf}$	*actual market rate of supplemental energy*
$RATE_R$	*actual market rate of regulation*
r_i	*raw regulation component of analyzed resource*
r_L	*regulation component of total system load*
Δr_i	*regulation of system load less the resource of interest*
σ	*standard deviation*
σ_i	*standard deviation of regulation component of analyzed resource*
σ_T	*standard deviation of regulation component of total system load*
σ_{T-i}	*standard deviation of regulation component of total system load less the analyzed resource*
T	*total*
t	*time*
x	*dummy variable*

EXECUTIVE SUMMARY

This report presents the results of Phase I of the California Renewables Portfolio Standard (RPS) Renewable Generation Integration Costs Study. The study is sponsored by the California Energy Commission in support of the California Public Utilities Commission's RPS implementation efforts. The goal of the study is to develop a methodology for determining the integration costs of California RPS eligible renewable generation projects. The study is motivated by the RPS's "least-cost, best-fit" bid selection criterion which requires that indirect costs be considered in addition to the energy bid price when selecting eligible renewable projects. The methodology will produce cost adders which can be added to a project's bid price during the bid selection process.

Integration costs are a subset of indirect costs and are defined as the costs and values of integrating an electrical resource such as a generation project into a system-wide electrical supply. Three primary categories of integration costs have been identified: capacity credit, regulation cost, and load following cost.

In Phase I of the study, the integration costs of California's renewable generation in 2002 was examined. Analyzing the existing installation of renewable generation provided an important basis for understanding the pertinent issues surrounding the study and a foundation for the remainder of the study which addresses new projects. Additionally, the Phase I results provide some values which can be applied immediately to RPS bid selection while the methodologies are refined and finalized in the subsequent phases of the study.

The following sections present the Phase I findings for each category of integration cost.

Capacity Credit

Resource	Relative Capacity Credit
Medium Gas	100.0%
Biomass	97.8%
Geothermal (constrained)	73.6%
Geothermal (unconstrained)	102.3%
Solar	56.6%
Wind (Altamont)	26.0%
Wind (San Gorgonio)	23.9%
Wind (Tehachapi)	22.0%

The capacity credit of a generator, while categorized as an integration cost, is not a cost at all. Instead, it is the value of a generator's contribution to the reliability of the overall electrical supply system. Relative capacity credit values based on a gas reference unit were determined for various renewable technologies.

A reliability model of the generation supply system was developed based on data from the California ISO (CaISO) and from a commercial generator reliability database. The model was calibrated and generator reliability metrics were calculated. As detailed further herein, maintenance outage scheduling was excluded from the calculation.

Relative capacity credit values are shown in the table above. As expected, the biomass and geothermal resources have high capacity credit values (in the absence of fuel or other constraints) because they behave most like conventional resources. The wind capacity credit is significantly lower than the other resources, but shows that wind can help reduce system risk, albeit by a modest amount when compared to other resource types. The wind capacity credit values are consistent with what we would find for a conventional unit with a very high forced outage rate — about 75%.

During the 12 September 2003 public workshop and the public draft review period of this report, several parties commented (see Appendix C) that the solar capacity credit value was lower than they expected. As discussed in Section C.1.1, there are several possible reasons for this. However, until sufficient analysis is performed to verify the cause of the perceived discrepancy, the solar capacity credit value of 56.6% should not be applied toward any RPS bid evaluation or ranking.

A preliminary investigation of the effect of increasing penetration was performed by doubling the hourly output levels of each of the renewables under study. It was determined that the results above are conservative values which will remain applicable for at least a doubling of renewable capacity.

Several items have been identified for investigation in the subsequent phases of the study. First, as originally planned for Phase II, a thorough analysis of the effects of increased penetration, different technologies, siting, and various other parameters will be performed. Calculations will employ disaggregated data whenever possible so that differences between individual generators can be captured. Second, a simplified method for calculating the capacity credit will continue to be pursued. Third, a monetary value will be determined for the capacity credit so that a cost adder can be derived.

Regulation

The generating resources studied have quite minor impacts on the total system regulation requirements. The sheer size of the load results in a regulation cost for the aggregated load that is essentially identical to the total system regulation cost.

Resource	Regulation Cost ($/MWh or mills/kWh)
Total Load	-0.42
Medium Gas	0.08
Biomass	0.00
Geothermal	-0.10
Solar	0.04
Wind (Altamont)	0.00
Wind (San Gorgonio)	-0.46
Wind (Tehachapi)	-0.17
Wind (Total)	-0.17

An important note is that all of the results are quite small. They are, at best, at the edge of the error range for this data. We can clearly say that the impacts of the individual resources are not significantly larger than what is shown. However, it is difficult to have confidence in the precision of these small numbers. The CaISO data storage system was not designed to maintain the level of resolution needed for the analysis of small fluctuations.

Given the caution on the precision of the results, it is not surprising that both the medium gas plant and the solar plant have slightly positive numbers. The daily solar cycle tends to follow the daily load pattern. This primarily helps with load following and improves the performance of the solar plant in the energy market. A small benefit also flows into the regulation performance. Similarly, the medium gas plant tends to chase the energy market price, helping load following. A small portion of this benefit also flows into regulation performance.

Not unexpectedly the wind plants impose a small regulation burden on the power system. This was expected because there is no apparent mechanism that would tie the wind plant performance to the power system's needs in the regulation time frame and result in a benefit like there is for solar plants or conventional plants that are following price signals. The regulation burden is low because there is also no mechanism that ties wind plant fluctuations to aggregate load fluctuations in a compounding way either. Wind and load minute-to-minute fluctuations appear to be uncorrelated. Hence they greatly benefit from aggregation. In aggregate, the wind regulation burden is lower (on an energy basis) than that imposed by loads. Interestingly there is a range of regulation performance that may be related to the geographic location of the wind plants.

The geothermal plant also shows a small regulation burden. Most of the time the geothermal plant has steady output and would be expected to impose little or no regulation burden. Examination of the time series data shows that there are times when output from the geothermal plant becomes somewhat erratic, possible explaining the slight regulation burden seen here.

The biomass plant output was steady and imposed no regulation burden.

This preliminary analysis shows that there is little regulation impact imposed on the CaISO power system by the existing renewable resources. These results are sufficiently robust so that little impact should be expected if reasonable amounts of additional renewable resources are added to the system. The calculated impacts are close to the limits of the study accuracy.

It appears that different wind locations may have different regulation performance. This will be studied further in Phase II. Similarly, the overall study accuracy should be refined. One minute data on total system load and each of the resources should be collected and saved at higher resolution than the current system accommodates. Analysis should be performed quarterly and annually to update this report.

Load Following

The load following analysis in this effort focused on implicit costs associated with integration of renewable energy. Explicit, market settled costs were not considered. Integration of large amounts of renewable generators could potentially increase errors between scheduled and actual generation. Increases in scheduling error could potentially change the composition or size of the BEEP stack, the generator pool used to compensate for scheduling deviations. If such a distortion of the stack occurred it could shift the market to marginal generators, whose costs were higher. That could increase the price of energy in the market and thus create implicit costs which were imposed on the system by the renewable generators.

The analysis methodology first determined system forecasting and scheduling errors for the benchmark case without renewable generators. The scheduling coordinators typically schedule significantly less generation than is needed for on-peak load and rely upon the hour ahead market to provide the

RESOURCE	COMBINED FORECAST ERROR AND RENEWABLE SCHEDULING ERROR			
	Average Minimum		Average Maximum	
	MW	Compared to forecast error w/out renewables (%)	MW	Compared to forecast error w/out renewables (%)
Forecast error without renewables	-1909	100%	2220	100%
Biomass	-1897	99%	2218	100%
Geothermal	-1878	98%	2221	100%
Solar	-1870	98%	2220	100%
Wind (Altamont)	-1909	100%	2272	102%
Wind (San Gorgonio)	-1898	99%	2226	100%
Wind (Tehachapi)	-1884	99%	2281	103%
Wind (total)	-1870	98%	2377	107%
Scheduling bias	-5076	266%	1747	79%

balance. The difference between the forecast load and the scheduled load is defined as the scheduling bias. Forecast and scheduling errors in the benchmark case provide an indication of the variability inherent in operating the utility grid and are important because they define the normal range of errors without renewable generation impacts.

The next stage of the analysis was to calculate the scheduling errors for each renewable generator of interest. Worst case scheduling was used to estimate the impacts of the renewable generators. The analysis is therefore conservative

The total forecasting error including the renewable resources was calculated by combining the system forecasting error (without renewables) with the additional scheduling error produced by the renewable resource in question. The forecasting error including renewable generators was then compared against the benchmark case and reviewed to identify the significant differences between them. The goal of this analysis was to determine if the renewable resources significantly changed the forecasting error and modified the generator bid stack.

Based on the results of this analysis, the impacts of renewable generators are small when compared against the bias introduced by the scheduling coordinators. As discussed above, the scheduling bias provides an indication of the depth of the BEEP stack. Therefore impacts which are small relative to the scheduling bias were not considered to significantly change the stack size or composition. These results indicate that renewable resources have no significant impacts on the stack at current levels of market penetration and are sufficiently robust so that little impact should be expected if reasonable amounts of additional renewable resources are added to the system.

More detailed analyses are recommended for the subsequent phases of this study to evaluate the effects of increased renewable penetration and the impacts on contingency reserves.

1 INTRODUCTION

1.1 Historical Background

California's recently enacted Renewables Portfolio Standard (RPS, Senate Bill 1078)[1] requires the state's investor-owned utilities (IOUs) to increase the renewable portion of their energy mix with a goal of 20% renewable energy generation by 2017. Renewable generation projects will compete with each other to supply the IOUs, with the California Public Utilities Commission (CPUC) establishing a process to select the "least-cost, best-fit" projects. As stated in the RPS (399.14.a.2.B), the CPUC must:

> *...adopt a process that provides criteria for the rank ordering and selection of least-cost and best-fit renewable resources to comply with the annual California Renewables Portfolio Standard Program obligations on a total cost basis. This process shall consider estimates of indirect costs associated with needed transmission investments and ongoing utility expenses resulting from integrating and operating eligible renewable energy resources.*

The California Energy Commission (CEC), in support of the CPUC, organized a team to study integration costs in the context of RPS implementation. The analysis team is collectively referred to as the Methods Group. This report is the product of the first phase of the integration costs study.

1.2 Defining Integration Costs

Integration costs are the "indirect costs associated with… ongoing utility expenses from integrating and operating eligible renewable energy resources." In the RPS enabling legislation, the costs of transmission investments are explicitly differentiated from integration costs. As shown in Figure 1.1, the total cost will be the sum of the direct and indirect costs. Integration costs are a subset of the indirect costs.

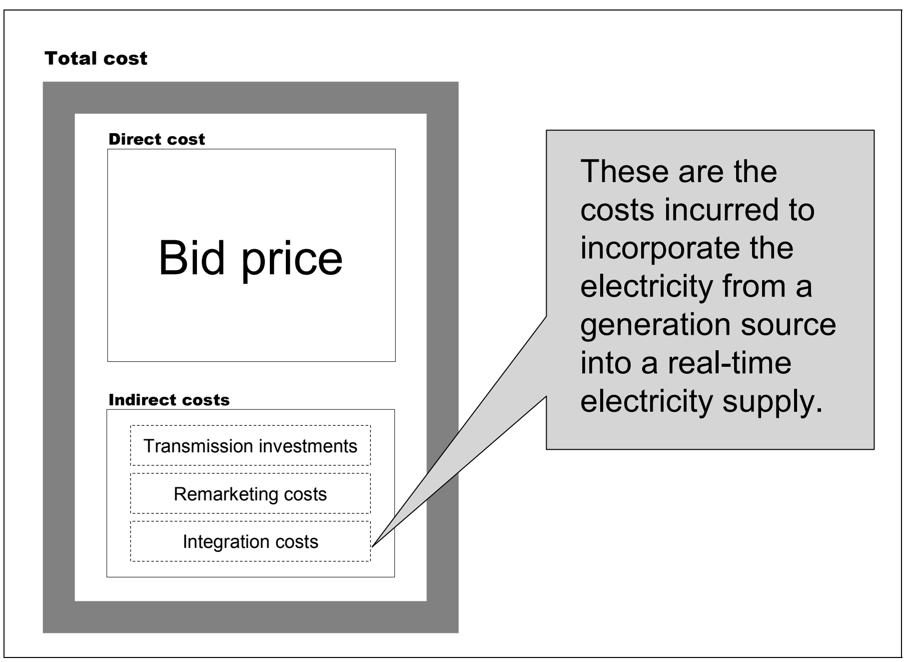

Figure 1.1 How integration costs fit in the least-cost, best-fit process.

Integration costs can be divided into three categories, as described below.

1.2.1 CAPACITY CREDIT

The California Independent System Operator (CaISO) must constantly manage the state's supply of power and energy to control the electrical grid. Generating capacity (power) is critical to assure the reliability of the electric system. A generator's ability to deliver power when needed provides capacity value to the system that is separate and distinct from the energy it generates. Additional generation capacity is a valuable asset because it increases reliability during peak demand periods. Generation from renewable energy sources is often intermittent in nature, which complicates the analysis of the capacity they provide the grid. As used here, the term *capacity credit* will define the capacity a generator adds to the system, as measured by the capacity of a gas reference unit that will result in the same level of system reliability. The capacity credit of a given generator is a function of the reliability of that generator and system demand. No generator is perfectly reliable, so every type of generator has a capacity credit which is less than 100% of its maximum rated power. Some generators, because of decreased reliability or intermittent resource availability, will have a lower capacity credit than others.

Renewable energy sources have operational characteristics that are different from conventional power generation facilities. One of the key differences is the intermittent production output of some renewable energy sources. The inability of the CaISO to control intermittent generation is a characteristic that has important ramifications for the integration of renewable generation sources into the network. Utilities are often reluctant to assign a capacity credit to renewable generators, largely because of the intermittent nature of the resource and the perceived difficulties in accurately forecasting power output. If an intermittent generator is unable to claim an operational capacity credit, then other generating resources must be committed in an amount equal to the operating level for the intermittent generator for a specific time period. An intermittent generator will have more value if it can replace conventional committed capacity, at least for some portion of the year.

An intermittent generation resource that can be counted on for capacity will maximize its contribution to system reliability. An accurate forecast allows the utility to count intermittent generation capacity and reduce costs without violating reliability constraints. The simplest benefit of an accurate intermittent generator forecast is that generation (capacity and energy) can be planned for and used to avoid the use of fuel to produce electricity. Renewable generators act as fuel saving facilities and benefits are increased if the output of renewable generators is used to offset the most expensive fuel in the mix. This simplified point of view is complicated by constraints imposed by integrating the intermittent resource with the rest of the electricity supply system.

Intermittent generators have capacity value if they increase the reliability of the system, even if the forecasts are not accurate. The best method for determining capacity value of intermittent generators is to calculate their *effective load carrying capability* (ELCC). This requires a reliability model that can calculate *loss of load probability* (LOLP), loss of load expectation (LOLE), or *expected unserved energy* (EUE). ELCC is a way to measure a power plant's capacity contributions based on its influence on overall system reliability. Using a measure such as ELCC, all power plants with a non-zero forced outage rate have an ELCC that is less than rated capacity (barring unusual plants with artificially low-rated capacity with respect to actual achieved capacity). The ELCC measure is often used as a way to compare alternative power plants, and can be easily applied to intermittent generators as well. A power plant's ELCC is typically calculated with an electric system reliability model or by a production-cost model.

1.2.2 REGULATION AND LOAD FOLLOWING

Ancillary services are the corrective actions needed to integrate electricity from generation sources into a larger, real-time electricity supply. In California, the CaISO purchases ancillary services to continually balance the imperfectly predicted, constantly changing load demand with the electricity supply from generators which do not perfectly match their prescribed output. All loads and generators, both conventional and renewable, require ancillary services at some time. These services exist without the presence or absence of renewable generation resources.

This study seeks to quantify the costs of ancillary services for various types of existing generation. Some studies have shown that renewable generators, because of their intermittent nature, require more ancillary services than others. Ancillary services are being considered in this study specifically so that we may quantify the difference in costs associated with various types of generation technologies currently operating throughout California. *Regulation* and *load following (supplemental energy)* are the two key ancillary services required to perform this function.[2]

Terminology associated with ancillary services has not been standardized across the utility industry and there has been confusion of terms. It is important to distinguish between the *impacts* imposed upon the power system and the *resources* or *services* the CaISO utilizes to compensate for these impacts. The impacts are imposed upon the power network by loads, uncontrolled generators, and transactions. The resources or services that compensate for these impacts are supplied by generators responding to *automatic generation control* (AGC) or the *automated dispatch system* (ADS).

In 1996 the Federal Energy Regulatory Commission (FERC), defined six ancillary services in its Order 888. This order did not discuss load following. Perhaps because of this omission, most utilities and independent system operators (ISOs) do not include load following in their tariffs. The absence of this service required some ISOs to acquire much more regulation than they otherwise would need. Perhaps because of these problems, FERC, in its notice on regional transmission organizations (RTOs), proposed to require that RTOs operate real-time balancing markets.[3] The responsive resources for these supplemental energy markets are generators that can change output every ten minutes as needed to follow load.

The CaISO obtains responsive resources to achieve the required real-time balancing of generation and load from the hourly regulation markets and the short-term energy markets. The alignment between the impacts that the CaISO must meet and the services it procures to meet those impacts is not perfect. Resources procured through the regulation markets, for example, could be used to provide load following, accommodate energy imbalance, or even supply base energy if there were no other alternatives. Load following itself is not a service which the CaISO procures directly. The CaISO meets its load following needs through short-term energy transactions, including both AGC generators and the supplemental energy market.

1.3 Project Goals

The overall project goal is to develop a valuation methodology for integration costs that can be applied to the selection process of RPS eligible generation projects. Because project selection is a public process for California, the final methodology will:

- use input data and analysis tools available in the public domain
- be fair, transparent, and coherent
- provide cost estimates that are representative of California

- be clearly defined, provide repeatable results, and be analyst independent

1.4 Project Schedule

The study is divided into three sequential phases, as shown in Figure 1.2.

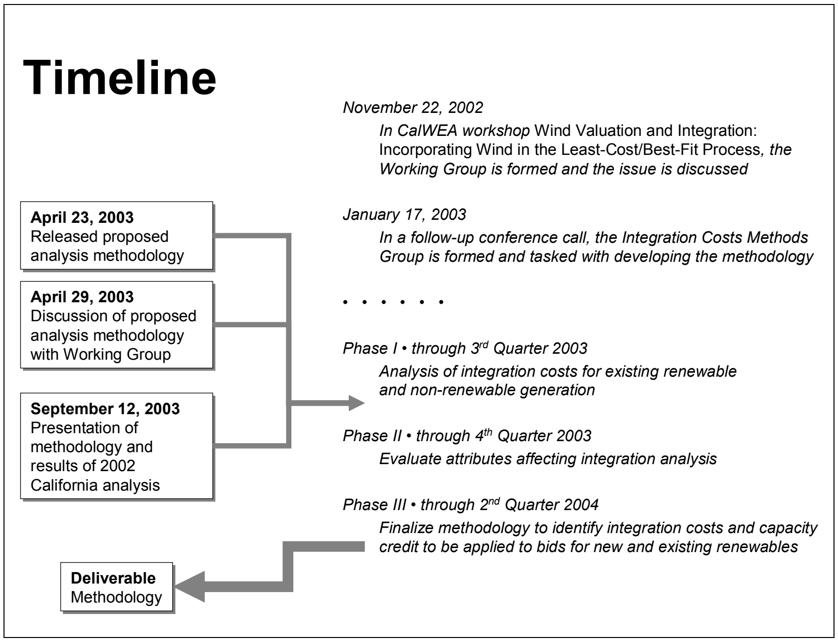

Figure 1.2 Timeline of the study.

1.4.1 PHASE I: ANALYSIS OF INTEGRATION COSTS FOR EXISTING GENERATION

The initial efforts in Phase I focused on documenting the methodologies to be used for evaluating the integration costs of California's existing renewable and non-renewable generation sources. Goals for development and documentation of the analysis methodologies were:

- The methodology should apply equally and fairly to all renewable generators eligible under the Renewables Portfolio Standard.
- The methodology should clearly define the analysis approach including the data requirements and the underlying assumptions.
- The documentation should provide a step-by-step process methodology to show how the data would be processed for each generator type.
- Each methodology should be used to analyze the same sample data file, so the results can be compared and contrasted.

During Phase I, the Methods Group was asked to select a single analysis methodology for implementation in the subsequent phases of work. The selection criteria for identifying the preferred approach were:

- Was the method independent of a specific institution or company?
- Could the method be applied fairly and consistently?
- Did the method provide results using a minimal amount of data?

- Was the method transparent and analyst independent?
- Has the method been published and peer reviewed?

1.4.2 PHASE II: ANALYSIS OF KEY ATTRIBUTES AFFECTING INTEGRATION ANALYSIS

In Phase II, the key attributes of renewable generators that affect integration cost will be identified and their contributions to integration cost will be analyzed using the methodology developed in Phase I. Recognizing the diversity of renewable energy resources, public input will be solicited to aid in the identification of the attributes. These attributes may include:

- various generator technologies
- location and climate
- level of penetration

Completion of Phase II is expected in December 2003.

1.4.3 PHASE III: FINALIZE METHODOLOGY FOR INTEGRATION COSTS FOR APPLICATION TO RPS BID SELECTION

In the third and final phase, the methodology developed in Phase I will be modified so that the attributes identified in Phase II are correctly modeled for the analysis of new renewable energy projects. The final methodology will be released openly to the public.

Completion of Phase III is expected in June 2004.

2 DATA DESCRIPTION

A selection of the data used in the 2002 analyses is presented and discussed below. The data itself provides insight into the behavior of the California electrical system and its generators. As discussed further below, the resolution of the data also dictates the limits of the analyses.

2.1 One Minute Data Set

This dataset contains generator and electrical system data collected at one minute intervals. While hourly data is more readily accessible, the analyses required data collected at a higher frequency. The data was provided by CaISO.

The renewable generator values are aggregates of similar plants. An aggregation is often referred to simply by the renewable type; for example, "biomass generator" refers to the aggregate of biomass plants, not an individual generator or plant. Aggregation was necessary to protect the confidentiality of individual plants. The generator aggregates are further described below in Sections 2.1.4 through 2.1.7. The descriptions are intentionally limited to preserve confidentiality.

2.1.1 CAISO PLANT INFORMATION (PI) SYSTEM

The data was extracted from CaISO's plant information (PI) system. CaISO's PI system stores operation data for the entire state. It contains over 180,000 data fields, including extensive generator data. Because the amount of information collected is so large, the PI system uses a compression scheme to store its data. The compression scheme is lossy, so some data accuracy is sacrificed for more compact storage.

The data was retrieved from the PI system using manual and scripted Microsoft Excel interfaces.

2.1.2 DATA EXTRACTED

The following one minute data was retrieved for 2002:

- System Data
  - Total load (MW)
  - Total generation (MW)
  - Area Control Error (MW)
  - Actual frequency (Hz)
  - Scheduled frequency (Hz)
  - Actual interchange (MW)
  - Scheduled interchange (MW)
  - Dynamic interchange schedule (MW)
  - Total regulation (MW)
  - Deviation from Preferred Operating Point (MW)

- Generator Power Output Data (MW)
  - An aggregate of biomass plants
  - An aggregate of solar plants
  - An aggregate of geothermal plants
  - Aggregated wind plants in Altamont

- Aggregated wind plants in San Gorgonio
- Aggregated wind plants in Tehachapi
- Aggregated output of all wind plants
- Several AGC and non-AGC conventional generators

2.1.3 SYSTEM DATA

The total system load for the year is presented in Figure 2.1, using one minute average data.

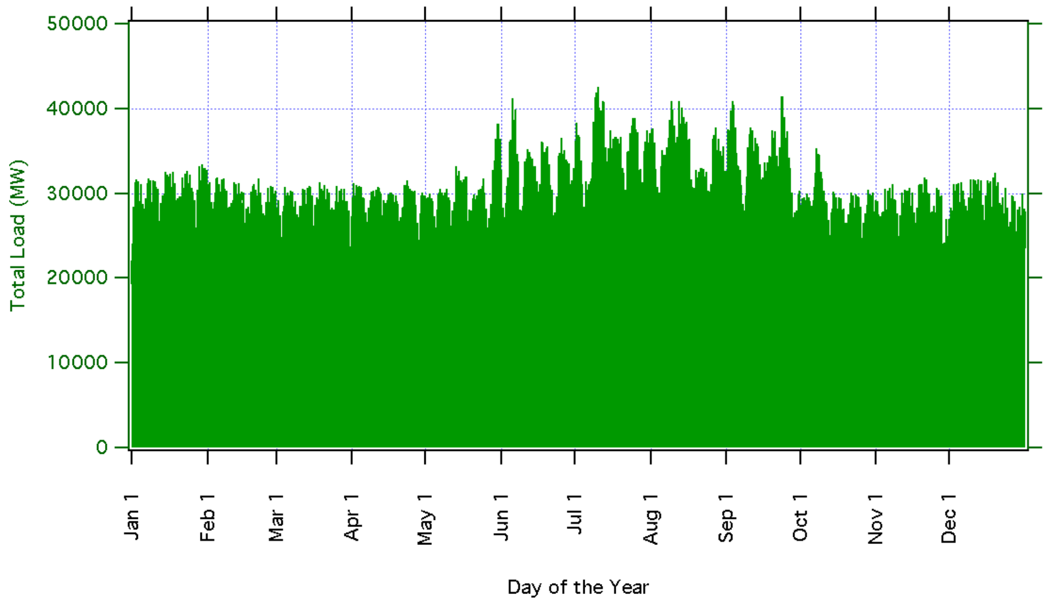

Figure 2.1 Total system load of 2002.

The annual amount of generation and imports are provided in Figure 2.2, while Figure 2.3 through Figure 2.6 show generation and imports for several example periods.

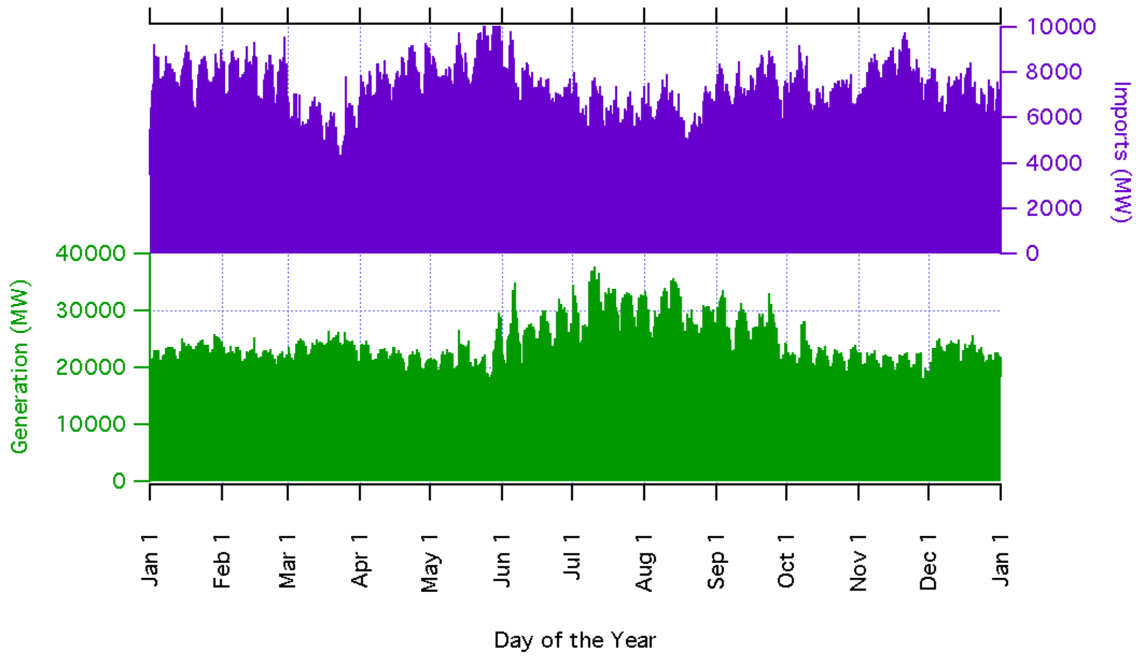

Figure 2.2 Total generation and imports of 2002.

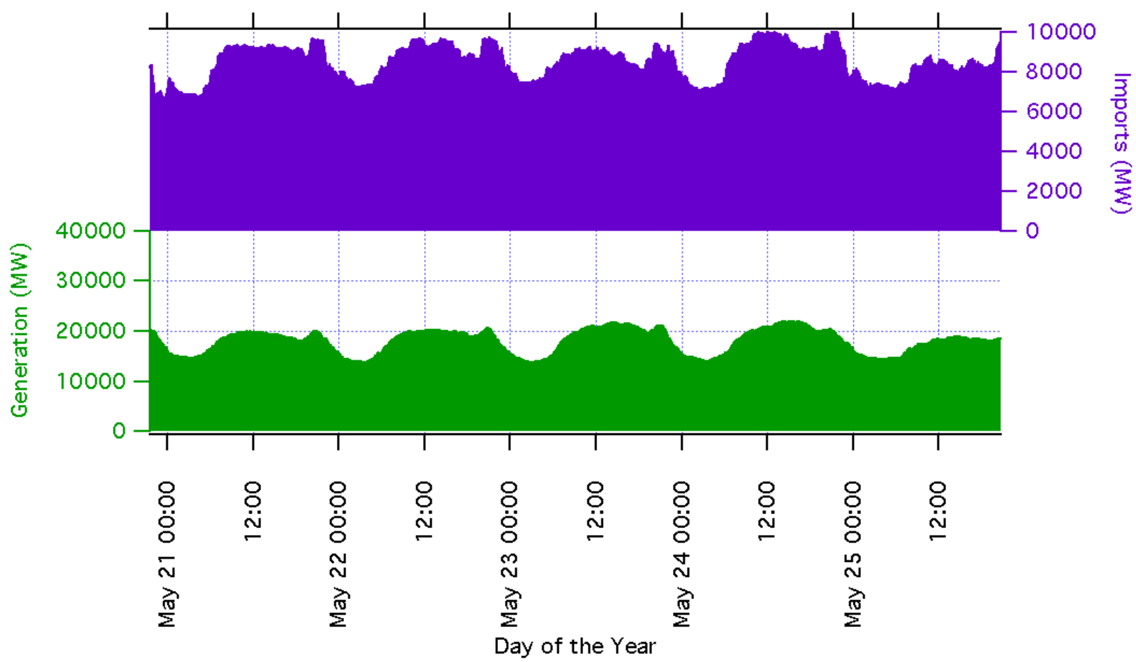

Figure 2.3 Generation and imports for several days in May 2002.

Figure 2.3 shows that imports can sometimes follow load quite well. Conversely, Figure 2.4 shows that imports are sometimes out of phase with the daily load pattern, peaking late at night when loads are low.

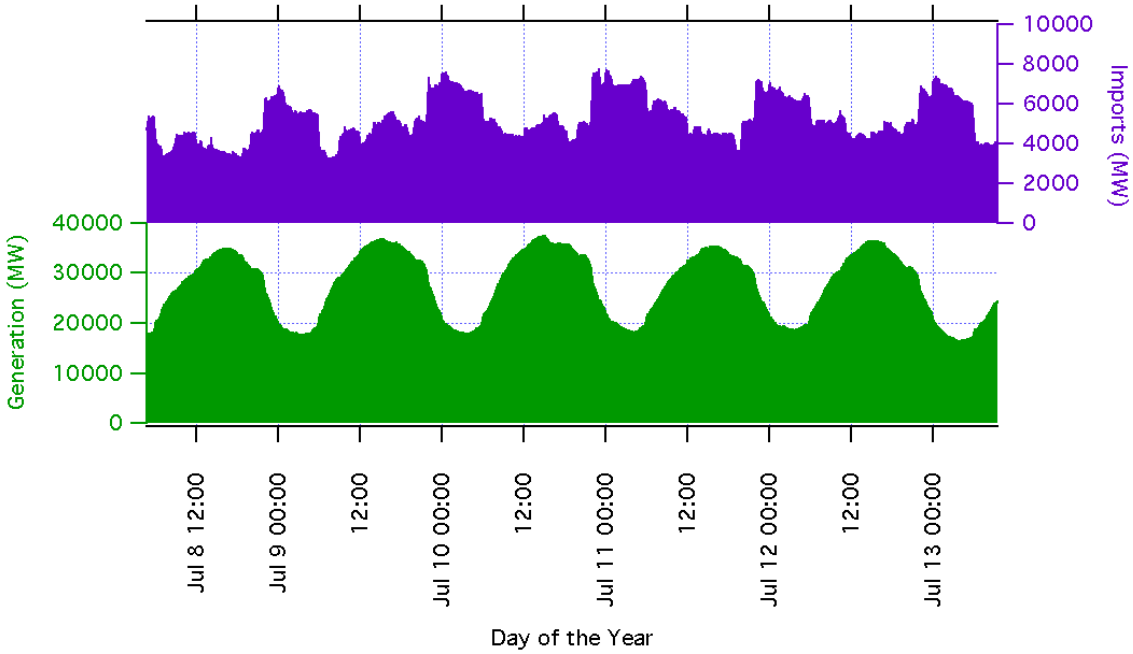

Figure 2.4 Generation and imports for several days in July 2002.

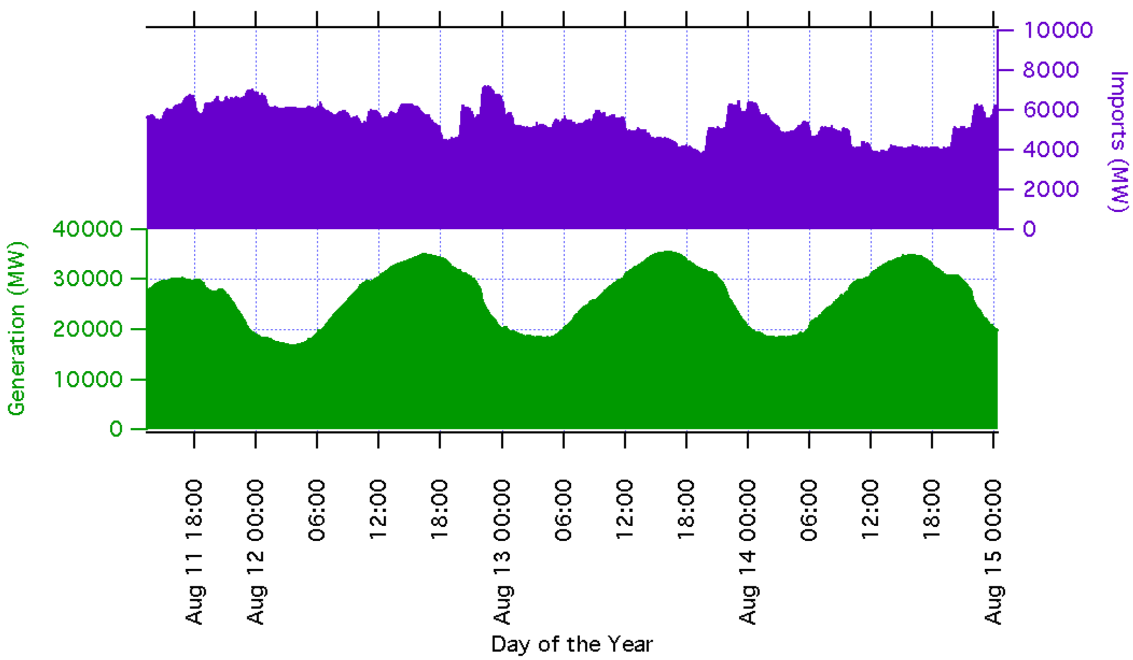

Figure 2.5 Generation and imports for several days in August 2002.

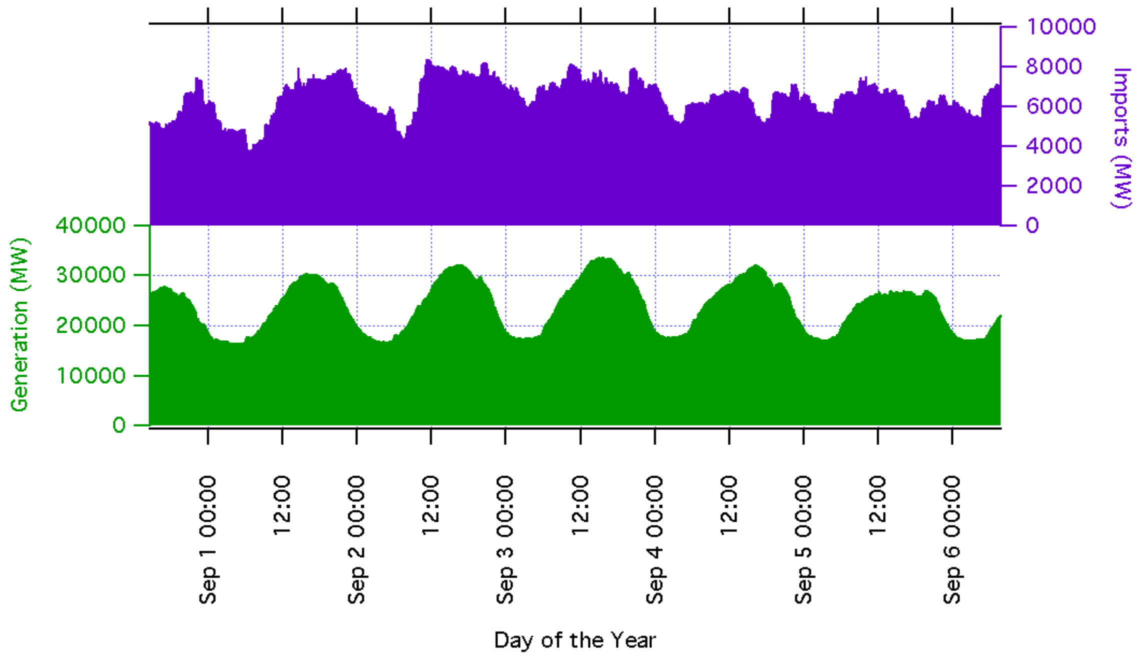

Figure 2.6 Generation and imports for several days in September 2002.

The rates of change per minute for the load and generation data were calculated from the one minute data. This data provides information about how quickly the total load was changing and how fast individual generators were moving. The rate of change was expressed in MW per minute and histograms were prepared to show the fraction of the year that was spent at a given rate of change. Figure 2.7 presents the rate of change histogram for the total system load.

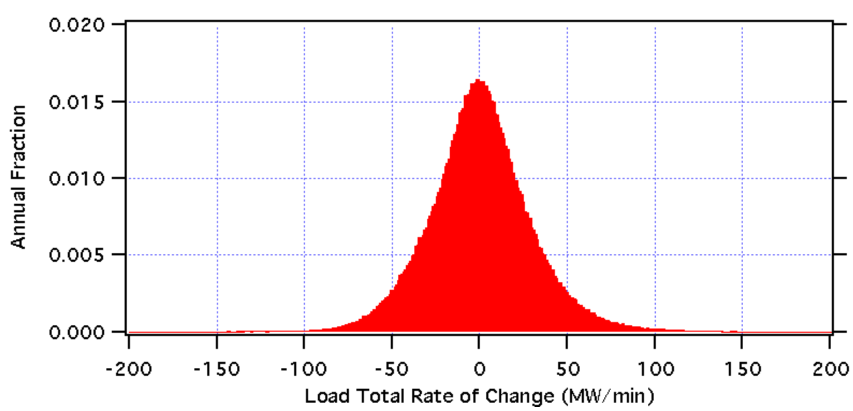

Figure 2.7 Rate of change histogram of total system load for 2002.

Figure 2.8 shows the rate of change for a medium sized combined cycle gas generator that was selected as a representative conventional unit for comparison purposes.

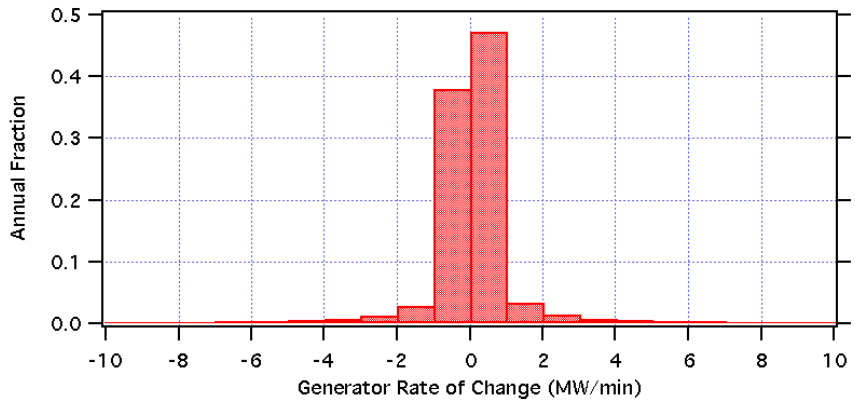

Figure 2.8 Rate of change histogram of power generation of the benchmark medium combined cycle gas generator for 2002.

This gas unit was used to provide the basis for comparing the output from various types of generating units. Plots comparing the gas unit and each of the renewable types are presented in the following sections. The data in these plots were normalized using the maximum one minute output for the year.

2.1.4 SOLAR DATA

The solar data is a partial aggregate of solar plants in California. Assuming the maximum power output of the year is equal to the rated capacity of the plants, the aggregate encompasses approximately 75% of the installed solar nameplate capacity in California. The aggregate is able to represent such a large portion of the installed capacity because there are relatively few solar plants. Figure 2.9 presents the power generation of the aggregate of solar plants as compared with the medium gas plant. The solar rate of change histogram is presented in Figure 2.10.

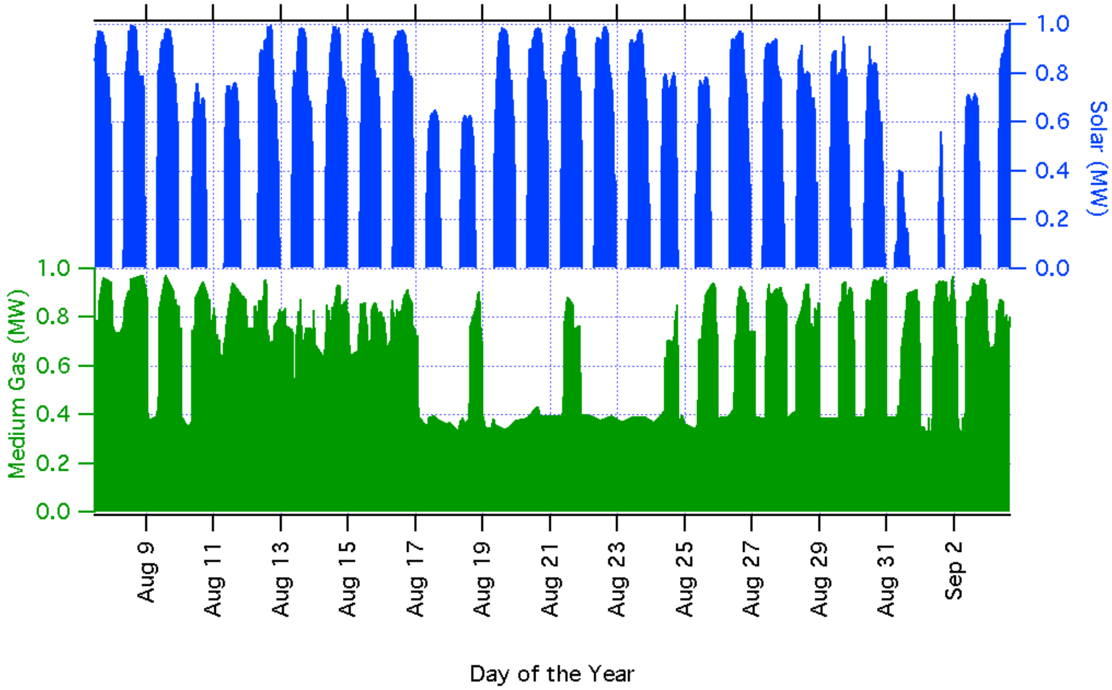

Figure 2.9 Generation of aggregated solar plants compared to generation of benchmark medium gas plant.

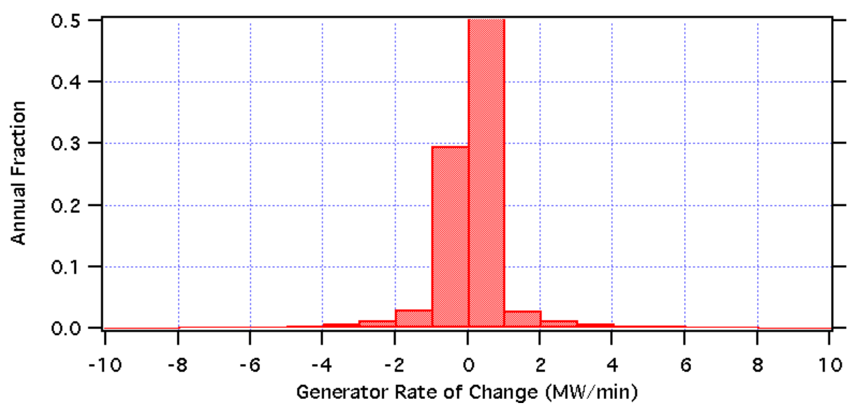

Figure 2.10 Rate of change histogram of power generation of the aggregated solar plants for 2002.

2.1.5 GEOTHERMAL DATA

The geothermal data is an aggregate of four geothermal plants in California. Assuming the maximum power output of the year is equal to the rated capacity of the plants, the aggregate encompasses approximately 5% of the installed geothermal nameplate capacity in California. Figure 2.11 presents geothermal generation as compared with the medium gas plant. The geothermal rate of change histogram is presented in Figure 2.12.

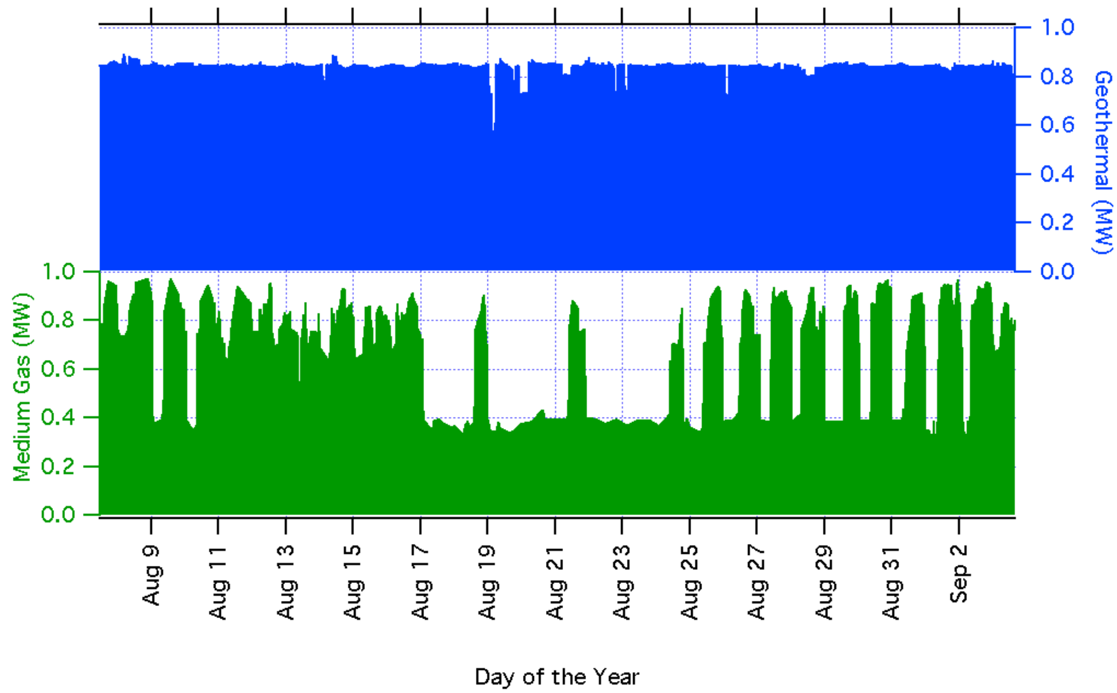

Figure 2.11 Generation of aggregated geothermal plants compared to generation of benchmark medium gas plant.

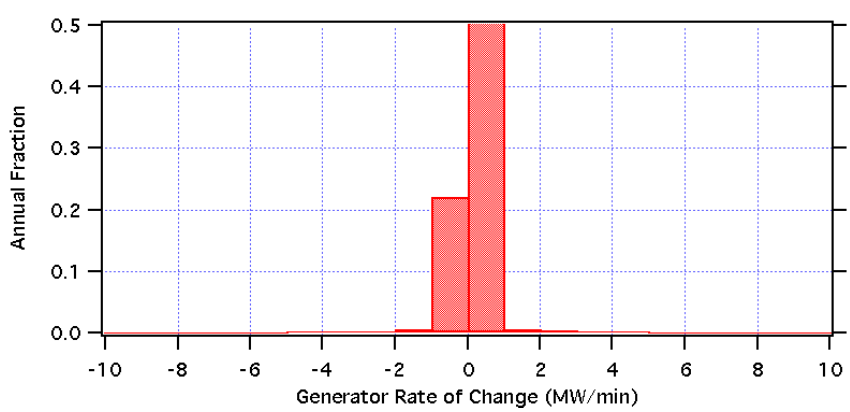

Figure 2.12 Rate of change histogram of power generation of the aggregated geothermal plants for 2002.

2.1.6 BIOMASS DATA

The biomass data is a partial aggregate of biomass plants in California. Assuming the maximum power output of the year is equal to the rated capacity of the plants, the aggregate encompasses approximately 38% of the installed biomass nameplate capacity in California. Figure 2.13 presents biomass generation as compared with the medium gas plant. The biomass rate of change histogram is presented in Figure 2.14.

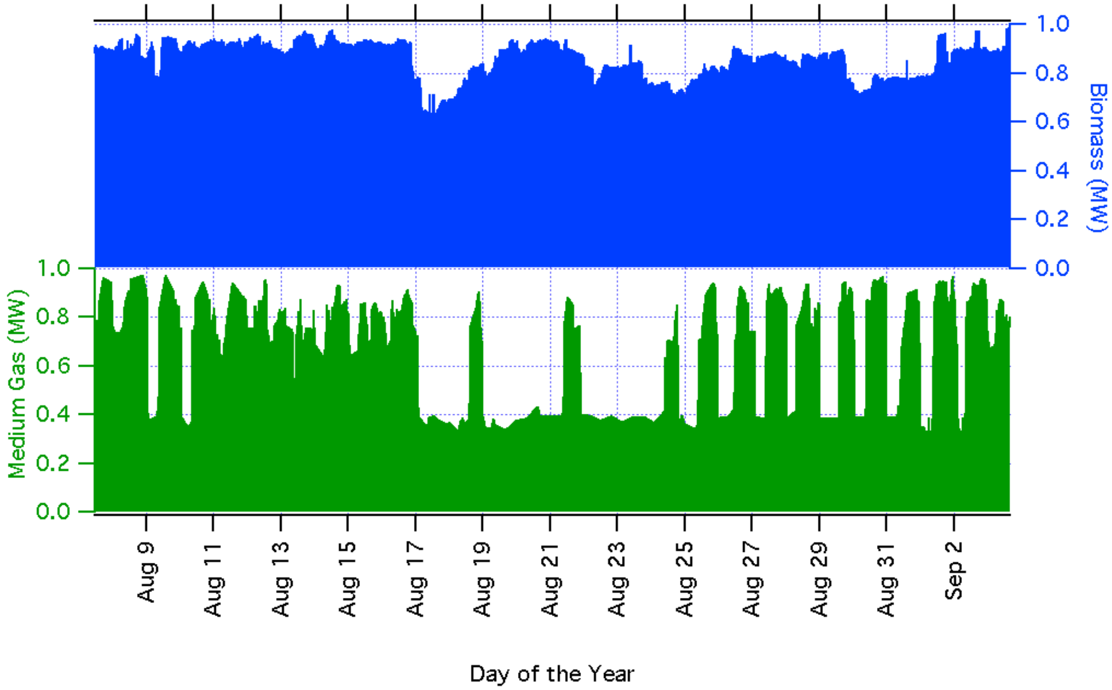

Figure 2.13 Generation of aggregated biomass plants compared to generation of benchmark medium gas plant.

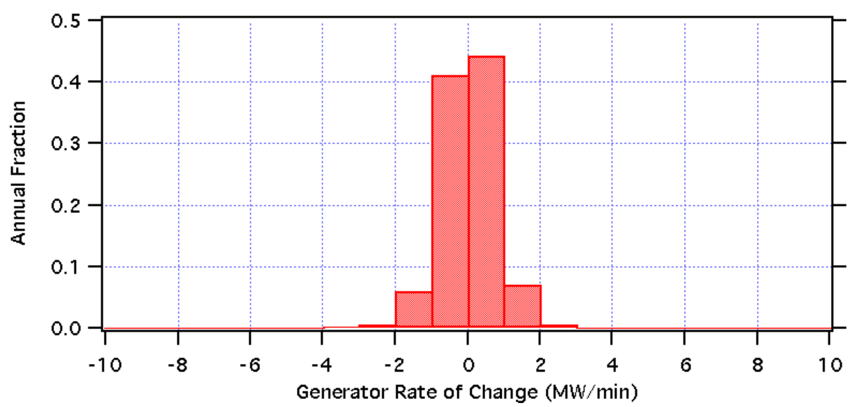

Figure 2.14 Rate of change histogram of power generation of the aggregated biomass plants for 2002.

2.1.7 WIND DATA

The wind data includes both regional (Altamont, San Gorgonio, and Tehachapi) and statewide aggregates. The statewide aggregate, referred to as the total, is composed of all the wind specific generation data collected by CaISO. Assuming the maximum power output of the year is equal to the rated capacity of the plants, the total wind aggregate encompasses approximately 70% of the installed wind nameplate capacity in California. The remaining 30% of capacity is either offline, outside of CaISO's control area, or recorded by CaISO in a non wind specific aggregate. Figure 2.15 and Figure 2.16 present the wind power generation in the Tehachapi region as compared with the medium gas plant. Power generation rate of change histograms are presented for various regions in Figure 2.17 through Figure 2.20.

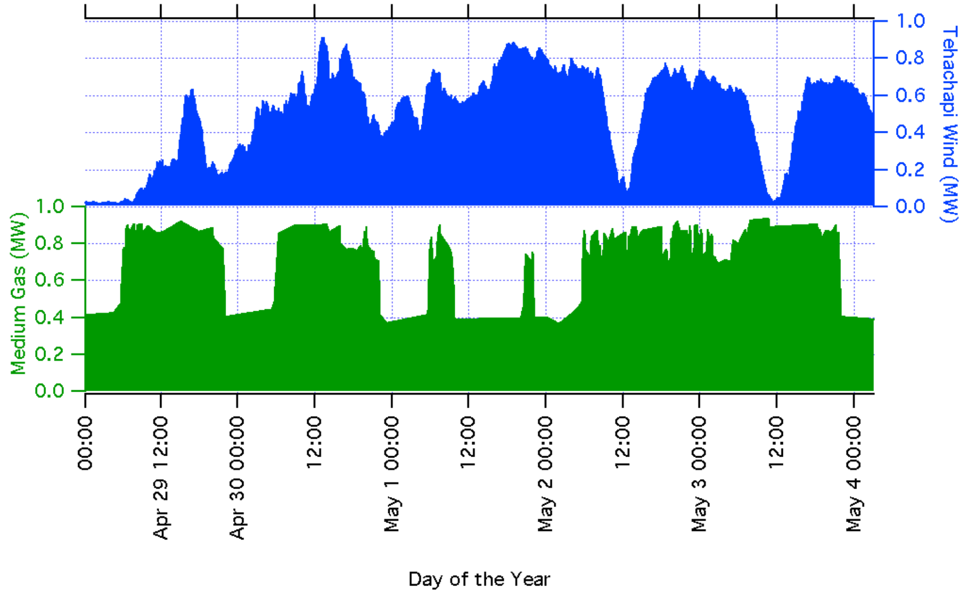

Figure 2.15 Generation of wind plants in Tehachapi region compared to generation of benchmark medium gas plant in May 2002.

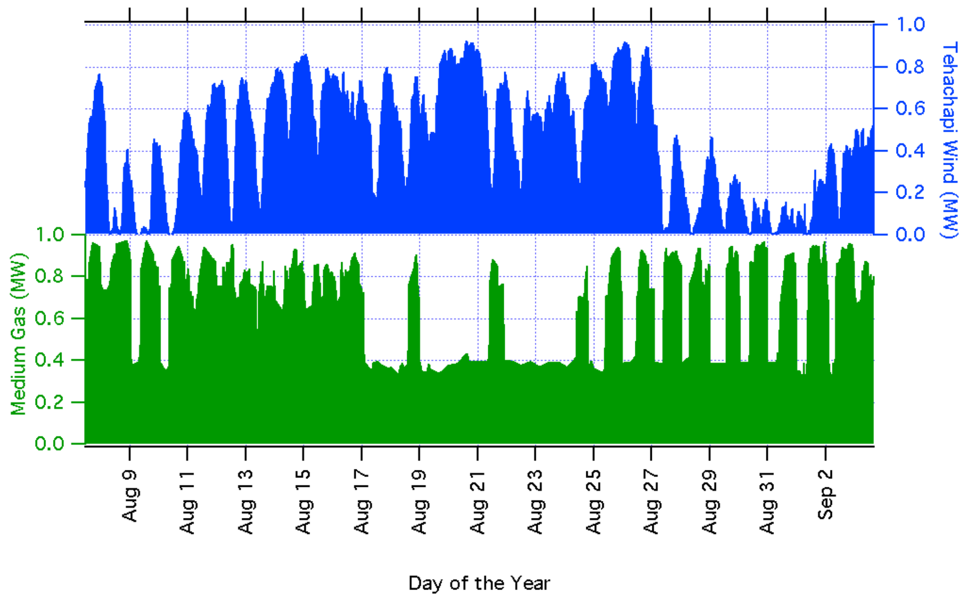

Figure 2.16 Generation of wind plants in Tehachapi region compared to generation of benchmark medium gas plant in August 2002.

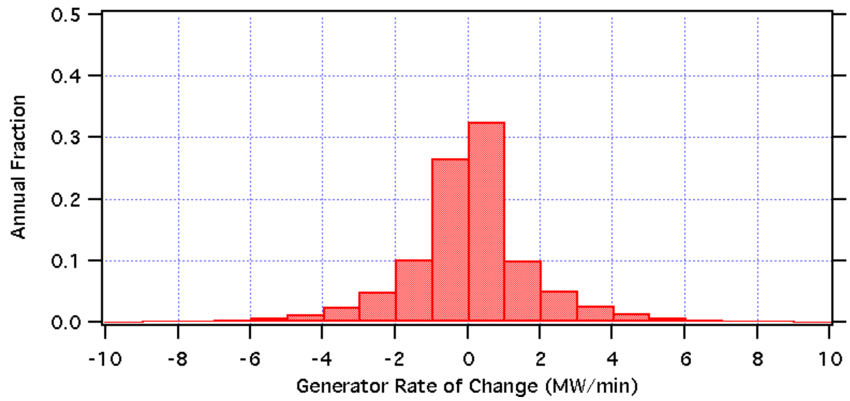

Figure 2.17 Rate of change histogram of power generation of the wind plants in the Tehachapi region for 2002.

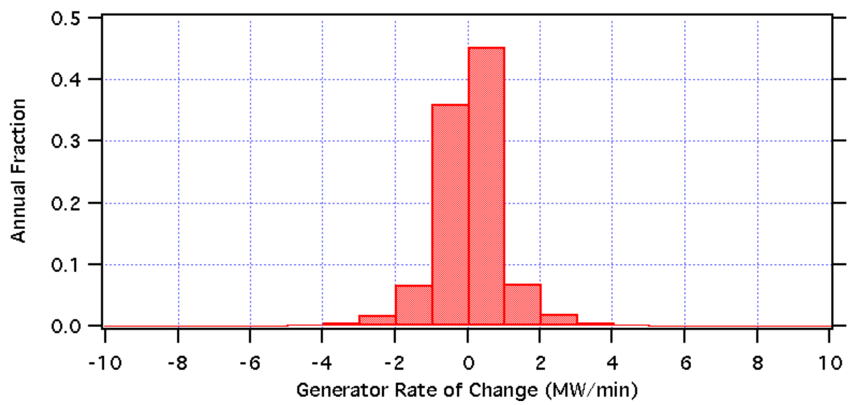

Figure 2.18 Rate of change histogram of power generation of the wind plants in the Altamont region for 2002.

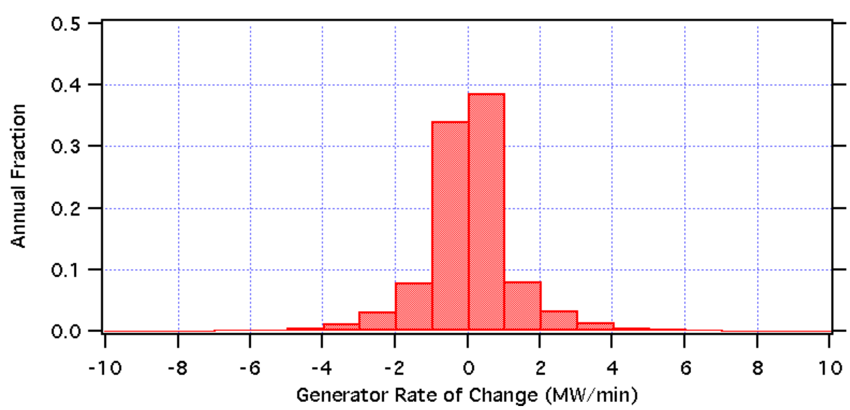

Figure 2.19 Rate of change histogram of power generation of the wind plants in the San Gorgonio region for 2002.

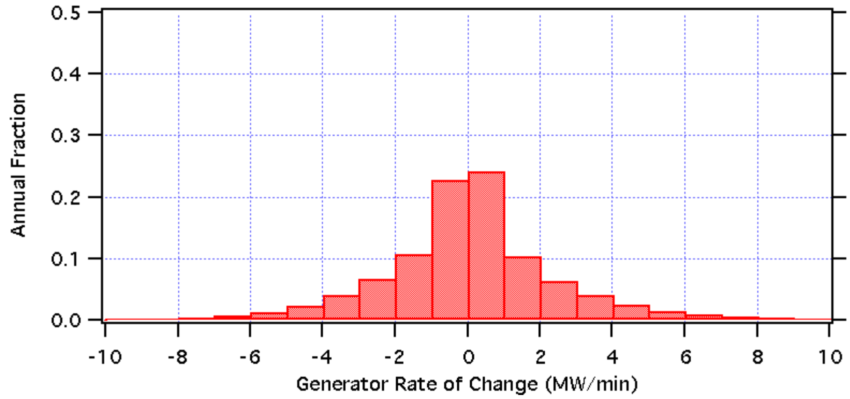

Figure 2.20 Rate of change histogram of power generation of the wind plants in California for 2002.

2.2 One Hour Data Set

This dataset is nominally referred to as the One Hour Data Set. It is composed primarily of data collected at one hour intervals, but includes some data collected at ten minute intervals. The critical distinction between the One Hour Data Set and the One Minute Data Set is that the One Hour Data Set is built from OASIS, CaISO's public database.

2.2.1 DATA SOURCE

OASIS is an acronym for Open Access Same-Time Information System. It is CaISO's web accessible public database at http://oasis.caiso.com/. OASIS contains current and archived market data for energy and transmission in California.

Data can be queried through an interactive web form and downloaded as a Microsoft Excel spreadsheet, PDF, text file with commas separated values (CSV), or XML. Queries can also be performed using specially constructed web addresses (URLs), although the download format is limited to XML.

The process of retrieving the One Hour Data Set was automated primarily with PERL, a versatile, freely available scripting language. The retrieved files were parsed and processed into a simple tabular format, also using PERL.

2.2.2 HOUR AHEAD FORECASTS AND SCHEDULE

Load data for all of 2002 was retrieved from OASIS. The load data consisted of hourly values of California's actual system load, scheduled load, hour ahead forecasted load, day ahead forecasted load, and two day ahead forecasted load.

The forecasted values are CaISO's predictions of load. The scheduled values are determined by the scheduling coordinators and submitted to CaISO; presumably, the scheduling coordinators schedule generation to meet these target values. The hour ahead values are actually set 150 minutes before the specified time so that CaISO has time to review and incorporate them into the system.

2.2.3 REGULATION MARKET DATA

The following hourly data for 2002 was retrieved from OASIS:

- regulation up, pre-rational buyer, procured (MW)
- regulation down, pre-rational buyer, procured (MW)
- regulation up price, pre-rational buyer, procured ($/MW)
- regulation down price, pre-rational buyer, procured ($/MW)
- regulation up, with rational buyer, procured (MW)
- regulation down, with rational buyer, procured (MW)
- regulation up price, with rational buyer, procured ($/MW)
- regulation down price, with rational buyer, procured ($/MW)
- regulation up price, with rational buyer, self-provided ($/MW)
- regulation down price, with rational buyer, self-provided ($/MW)

Regulation can be categorized in several nonexclusive ways:

- regulation up (frequently referred to simply as "reg up") and regulation down ("reg down")
- pre-rational buyer and rational buyer
- self-provided and procured

Regulation up and down are, respectively, regulation capacity above and below the regulation (AGC) generators' Preferred Operating Point. The Preferred Operating Point, as suggested by its name, is the preferred power setting of an AGC generator; presumably, it is an efficient setting which leaves adequate "maneuvering room" for a generator to increase or decrease generation to meet regulation demands. If regulation capacity above the Preferred Operating Point is required, then regulation up is purchased. Similarly, if regulation capacity below the Preferred Operating Point is required, then regulation down is purchased. Additional details are available in the CaISO presentation "Settlements Training; Ancillary Services: Automatic Generation Control"[4].

The rational buyer system allows a less expensive ancillary service to be purchased for an ancillary service need, even if the purchased ancillary service is faster than required. Regulation purchases that include the rational buyer may therefore include capacity that is used to meet regulation, spinning reserve, non-spinning reserve, or replacement reserve requirements. For the purpose of this study, pre-rational buyer regulation values, which account only for regulation capacity purchased for regulation, are needed. Additional details about ancillary services and the rational buyer are available in the CaISO presentation "Ancillary Services Rational Buyer Adjustment: Charge Type # 1011"[5].

Self-provided regulation is regulation capacity that a scheduling coordinator provides for its generation. Procured regulation is regulation capacity that CaISO must purchase to meet regulation needs beyond what is self-provided by the scheduling coordinators.

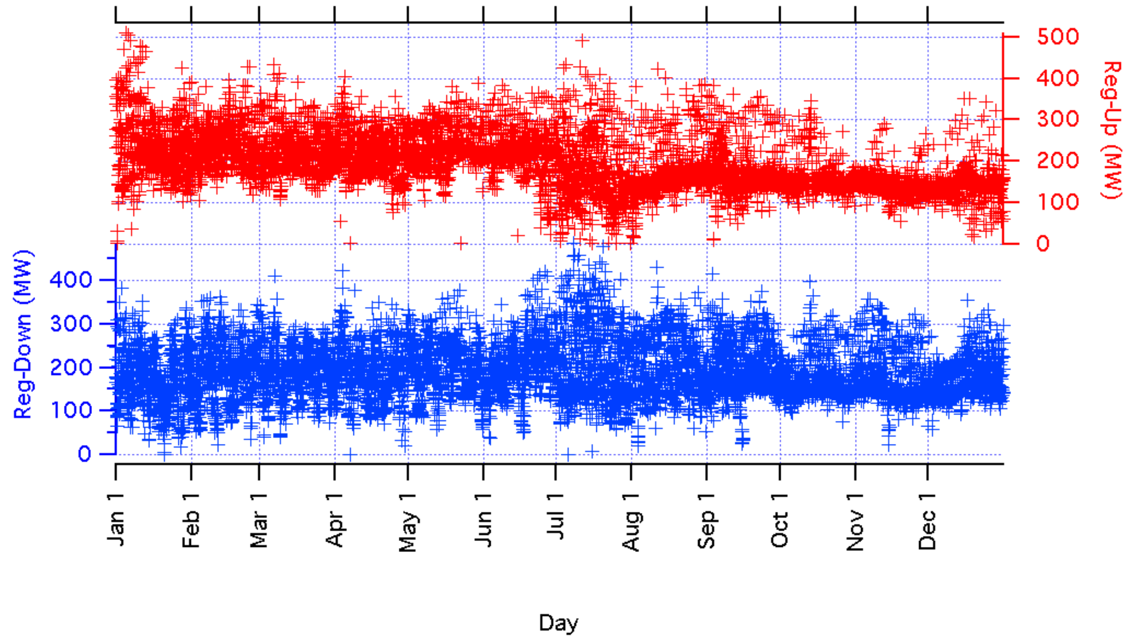

Figure 2.21 CalSO regulation purchases in 2002.

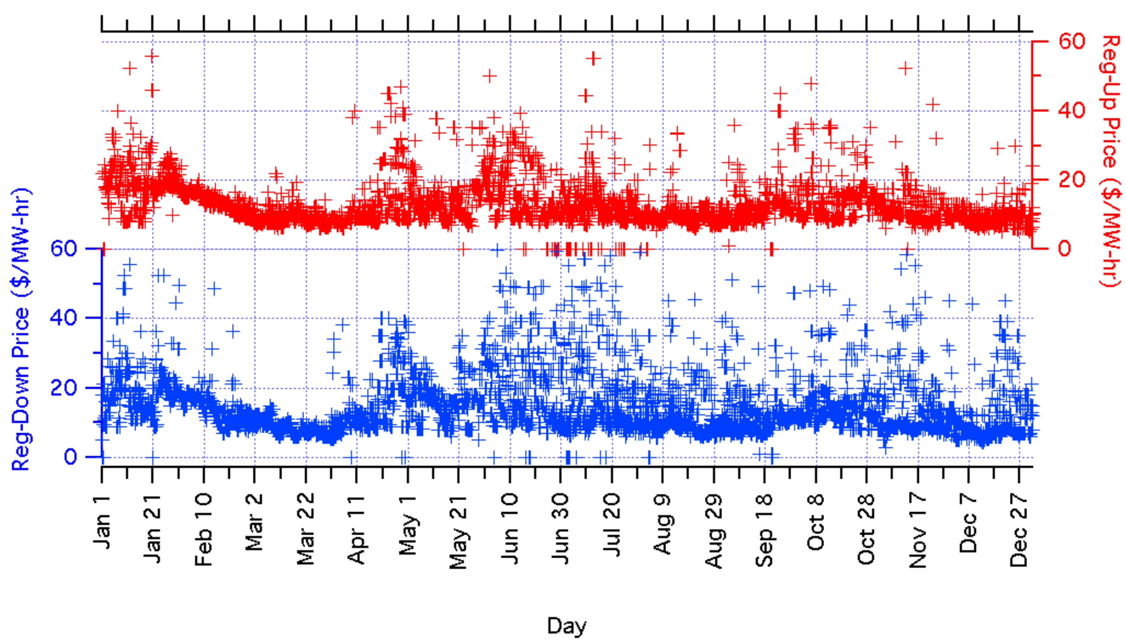

Figure 2.22 CalSO regulation market prices in 2002.

2.2.4 SUPPLEMENTAL ENERGY MARKET DATA

The data retrieved from OASIS for 2002 is listed below. Because the supplemental energy market operates on a ten minute basis, hourly data and ten minute data are both available.

- total incremental energy dispatch (MWh)

- total decremental energy dispatch (MWh)
- average incremental energy dispatch price ($/MWh)
- average decremental energy dispatch price ($/MWh)

The data also includes amounts and prices of energy dispatches purchased above the market clearing price.

An incremental energy dispatch, commonly referred to as an inc, is required when more energy is needed from the supplemental energy market. Presumably, this occurs when there is not enough actual generation to meet the actual load. When an inc is performed, a generator increases its energy output. Similarly, a decremental energy dispatch (dec) is required when actual generation is greater than actual load. When a dec is performed, a generator reduces its energy output.

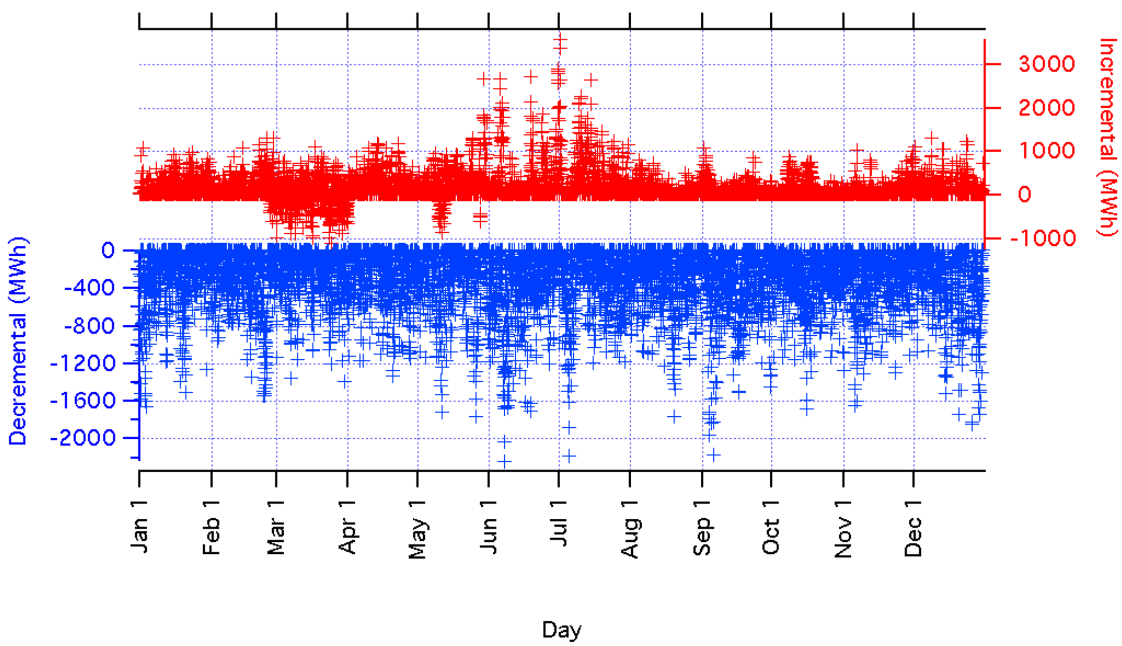

Figure 2.23 CalSO supplemental energy purchase in 2002.

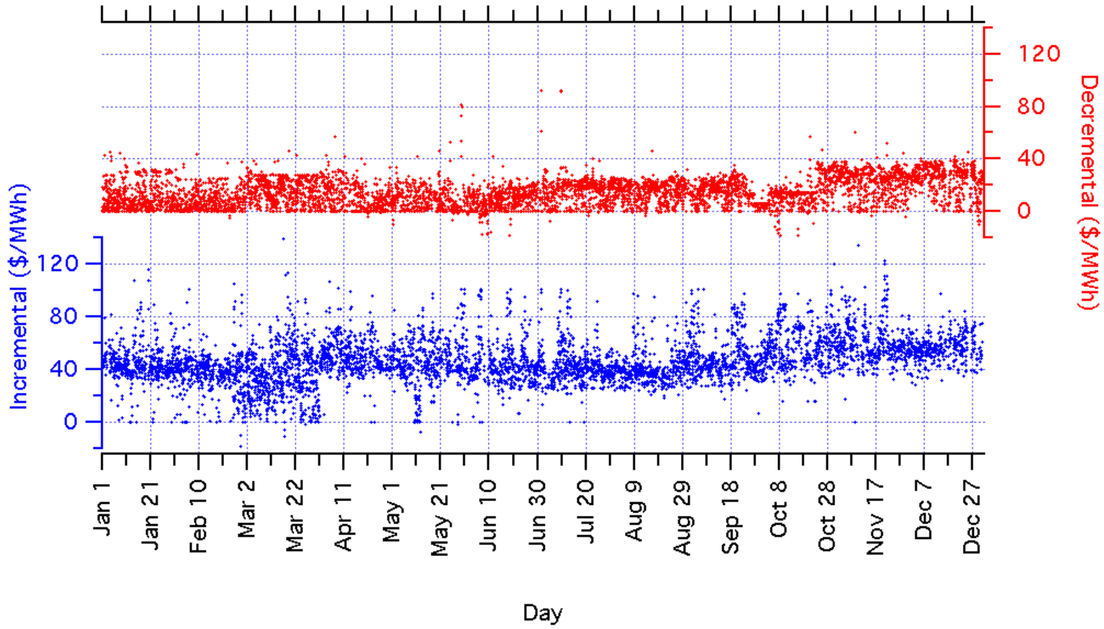

Figure 2.24 CaISO supplemental energy purchase prices in 2002.

2.3 CaISO Outage Data

Since the beginning of 2001, CaISO has published the Non-Operational Generating Units in California reports[6]. The reports are required by the California Public Utilities Code and detail generator outages in California.

Since July of 2001, four reports have been published daily. Each report entry lists:

- the name of the generator experiencing the outage
- whether the outage was planned or unplanned
- the maximum capacity of the generator
- the owner of the generator
- the zone in which the generator is located
- the amount of capacity curtailed

There is some ambiguity in the value of the curtailed capacity because it is the total of all outages that occur within the reporting period. For example, if within a reporting period, a generator has a 10 MW outage, returns to full capacity, and then has a 20 MW outage, the entry in that period's report should list a 30 MW outage.

All the outage data from 10 July 2001 to 20 June 2003 was retrieved, parsed, and then tabulated using a PERL script.

2.4 Data Error

The raw data was reviewed for various data errors and bad data was removed from the data file. The one minute data files contain 525,600 data points for each signal and identifying bad data required visual inspection and evaluation to assess the validity of suspect data. To aid in the evaluation, the rate of change was calculated for each signal. Extreme rate changes allowed rapid identification of data dropouts and spikes. The bad data was manually eliminated and left as blanks in the data series.

The PI data was also corrected for errors introduced by the change from Standard Time to Daylight Saving Time.

An evaluation of the stored data accuracy was performed by comparing total load values stored in two different databases. Total system load was recorded in both the PI and OASIS databases. The one minute PI data was averaged hourly, which allowed direct comparison against the hourly data acquired from the OASIS database. The difference between the PI and OASIS hourly values was used to determine the data storage error, as shown in Figure 2.25. The standard deviation of data storage error is 160 MW or ±0.6% of the average annual load.

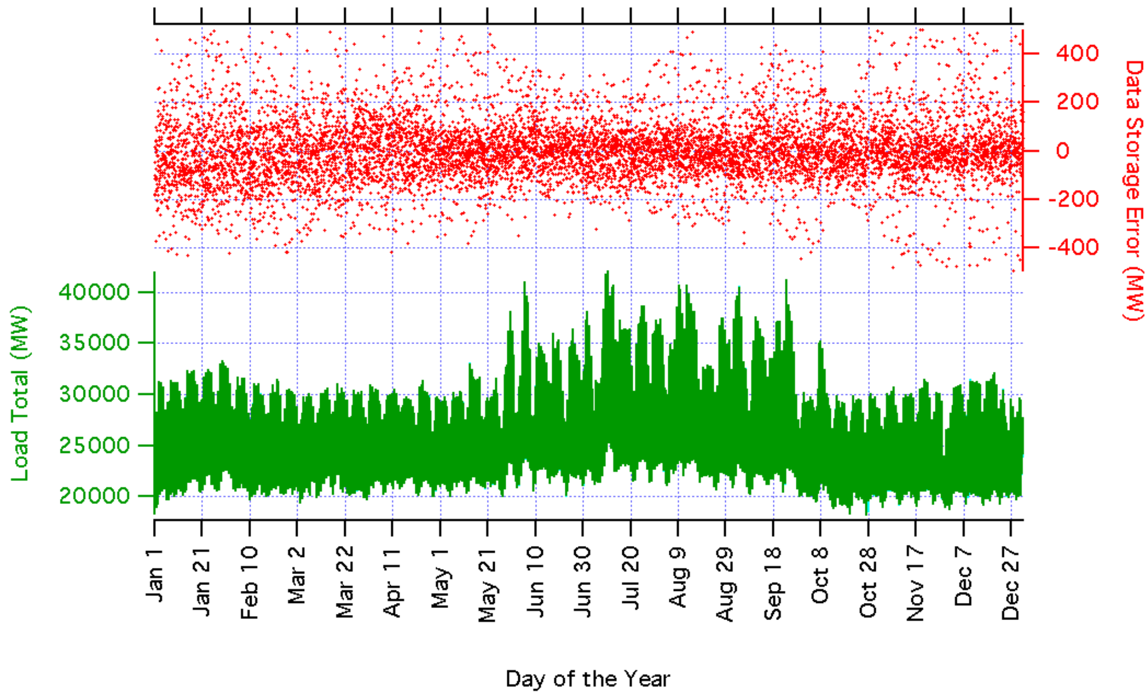

Figure 2.25 Data storage error of total load. The standard deviation of the total load data storage error is 160 MW.

The data accuracy was also evaluated by calculating ACE and comparing it to the recorded values. ACE was calculated from the control area tie line flow and frequency data from the PI system. The ACE error was then determined as the difference between the recorded values of ACE in the PI system and the calculated value. In this error analysis the standard deviation of the ACE error was 140 MW or ± 0.5% of the average system value. Figure 2.26 provides a graphical comparison of the recorded ACE values and the ACE error for the year.

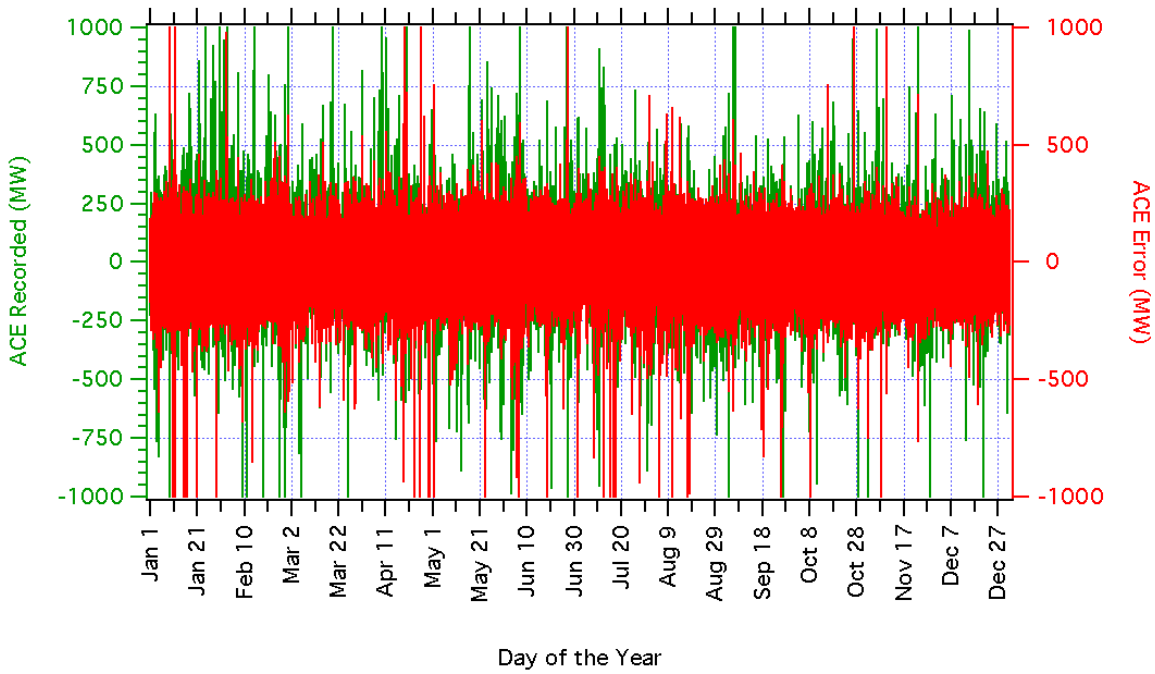

Figure 2.26 ACE recorded in the PI system and the ACE data error. The standard deviation of the ACE data error is 140 MW.

The results of these two data error evaluations indicate that the accuracy of the data stored in the PI database is accurate to ±0.5% of the recorded values. This analysis effort relied upon historical data and the storage accuracy cannot be modified for past data collections. It should be possible to increase the accuracy of the data stored in the PI system to support future efforts, which would thereby increase the accuracy and resolution of the analysis results.

3 CAPACITY CREDIT ANALYSIS

The standard techniques used to evaluate the reliability of power systems and how these techniques are used to measure planning capacity credit are based on Billinton and Allan[7]. Conventional power plants experience unplanned outages, either because of mechanical problems or other malfunctions. Episodes such as these are called forced outages. It is unlikely that conventional generators will experience a forced outage because of fuel shortages. During extended periods of anticipated low loads, generating units can be taken offline for routine maintenance. There is always a non-zero probability that any single generating unit will be on forced outage. Taking all such probabilities from each generator allows us to calculate the probability that enough generator units are on forced outage that the utility will be unable to meet its load. This probability is the loss-of-load probability (LOLP).

The primary advantage of a reliability-based assessment of capacity value is that it quantifies the risk of not supplying enough generation to meet loads. Because there is a non-zero probability that any generator can fail at any time, reliability-based methods can be applied to any type of generator. Most conventional generators have relatively low failure rates, although these rates can vary according to unit size, age, fuel type, and other factors. Intermittent renewable generators typically have low mechanical failure rates, but are not able to generate power when the resource isn't available. This intermittency must be brought in to the reliability calculation, and the standard methods for calculating reliability can be modified to do this.

3.1 Capacity Analysis Approach

3.1.1 EFFECTIVE LOAD CARRYING CAPABILITY

Using the concepts and techniques from reliability theory, we want to provide a measure of generating plant capacity credit that can be applied to a wide variety of generators, not just renewables. Although no generator has a perfect reliability index, we can use such a concept as a benchmark to measure real generators. For example, a 500-MW generator that is perfectly reliable has an ELCC of 500 MW. If we introduce a 500-MW generator with a reliability factor of 0.85, or equivalently, a forced outage rate of 0.15, the ELCC of this generator *might* be 425 MW; however, the ELCC value cannot be calculated by simply multiplying the reliability factor by the rated plant output.

In general, the ELCC must be calculated by considering hourly loads and hourly generating capabilities. This procedure can be carried out with an appropriate production-simulation or reliability model. The electricity production simulation model calculates the expected loss of load. The usual formulation is based on the hourly estimates of LOLP, and the LOLE is the sum of these probabilities, converted to the appropriate time scale. The annual LOLE can be calculated as:

$$LOLE = \sum_{i=1}^{N} P(C_i < L_i) \qquad [3.1]$$

where *P()* denotes the probability function, *N* is the number of hours in the year, C_i represents the available capacity in hour *i*, and L_i is the hourly utility load. To calculate the additional reliability that results from adding intermittent generators, we can write *LOLE'* for the *LOLE* after renewable capacity is added to the system as:

$$LOLE' = \sum_{i=1}^{N} P\left[(C_i + g_i) < L_i\right] \qquad [3.2]$$

where g_i is the power output from the generator of interest during hour i. The ELCC of the generator is the additional system load that can be supplied at a specified level of risk (loss of load probability or loss of load expectation).

$$\sum_{i=1}^{N} P(C_i < L_i) = \sum_{i=1}^{N} P\left[(C_i + g_i) < (L_i + \Delta C_i)\right] \qquad [3.3]$$

Calculating the ELCC of the renewable plant amounts to finding the values ΔC_i that satisfy equation 3.3. This equation says that the increase in capacity that results from adding a new generator can support ΔC_i more MW of load at the same reliability level as the original load could be supplied (with C_i MW of capacity). To determine the annual ELCC, we simply find the value ΔC_p, where p is the hour of the year in which the system peak occurs after obtaining the values for ΔC_i that satisfy the equation. Because LOLE is an increasing function of load, given a constant capacity, we can see from Equation 3.3 that increasing values of ΔC_i are associated with declining values of *LOLE*. Unfortunately, it is not possible to analytically solve Equation 3.3 for ΔC_p. The solution for ΔC_p involves running the model for various test values of ΔC_p until the equality in Equation 3.3 is achieved to the desired accuracy.

Although the level of detail of the input data varies between models, hourly electric loads and generator data is required to calculate LOLE. Common outputs from these models include various costs and reliability measures, although cost data are not used to perform system reliability calculations. Some of the models used for these calculations are chronological, and others group related hours to calculate a probability distribution that describes the load level.

3.1.2 SIMPLIFIED CAPACITY CREDIT CALCULATION METHODS

This discussion has focused so far on standard approaches of measuring power plant capacity credit. Although reliability models provide the most accurate result, they require significant modeling effort. Various ad hoc methods for calculating wind plant capacity credit have been proposed, many of them using the capacity factor over some relevant time period. Related approaches, like those described by Wan[8], use the median value of the wind plant over a recent history during the utility peak period. Other approaches have been suggested for situations where the appropriate modeling tools aren't available. These methods can often provide reasonable approximations to reliability-based methods.

Milligan & Parsons[9,10] compared a full complement of ELCC calculations to various capacity factor calculations. The results of these studies provide a benchmark of how well various capacity-factor measures can approximate the ELCC, as calculated by a reliability model. The first of the two simplified methods (NREL method 1) ranked all loads by LOLP (calculated using system data without intermittent generation), and then selected the top 10% of these loads. For the time periods represented by these loads, the intermittent generator capacity factor was calculated, and provided a reasonable approximation of the ELCC. The second method (NREL method 2) replaced the LOLP ranking with a ranking based only on the magnitude of the load. This second approach is somewhat easier and does not require the use of a reliability model, but is not quite as accurate as the LOLP ranking method.

Although this work focused on wind power plants, these techniques would be equally applicable to other intermittent technologies and the conclusions remain relevant. First, although capacity factor might be useful as an approximation to capacity credit, this prior work indicated that these approximations may consistently *underestimate* the ELCC value. Second, the accuracy of capacity factor methods is sensitive to both the number of hours used and the method used to select the hours. Third, intermittent plants contribute to overall system reliability during non-peak hours.

Ad hoc methods that calculate the renewable plant capacity factor over a very small number of hours surrounding the peak may not adequately capture any impacts on system reliability. For example, a wind plant that produces at its rated capacity during a very small number of hours surrounding the peak would be rated with a capacity value at or near its rated capacity. However, such a plant would not provide the same level of capability during other near-peak hours as a conventional plant could potentially provide. Conversely, a wind plant that is given a capacity value of 0 might contribute significant levels of output during near-peak hours when system reliability is still critical.

3.2 Capacity Analysis Results

For the California study the ELCC calculation procedure was altered so that the ELCC of the renewable generator can be calculated relative to a base reference unit. To accomplish this, equation 3.2 was used to calculate the reliability contribution of the renewable generator in the usual way. But instead of using equation 3.3 for the next step, the renewable generator was removed, and the gas reference unit was added in small increments until the LOLE’ from the reference unit matched the LOLE’ from the renewable generator. The amount of capacity added from the reference unit is the ELCC of the renewable generator.

3.2.1 ANNUAL SYSTEM LOSS OF LOAD EXPECTATON

For the RPS Integration study we built a reliability model of the generation supply system based on data from the ISO and from a database called BaseCase. BaseCase is a product of Resource Data International. For each hour of the year, the reliability model calculated the LOLP. So that the benchmark could be done in a reproducible manner, the overall system reliability level was calibrated by adjusting the hourly loads until the standard 1 day/10 years LOLE was achieved. This reliability level is often used as a standard for utilities and provides a reasonable trade-off between cost and reliability.

The original data included detailed maintenance outage data from the California generators. When that data was included in the ELCC calculations, the impact of maintenance scheduling had a significant impact on the ELCC of the renewable generators. This impact is caused by a shift in the hourly risk profile when a generator is taken out of service. The ELCC of a generator depends on its ability to reduce risk of capacity insufficiency. So if a relatively large fraction of generators are unavailable, this shift in the risk profile will have a direct impact on intermittent renewables’ ELCC because of the interplay in the timing of intermittent power delivery with the maintenance schedule. After significant discussion at the Public Workshop in Sacramento on September 12, 2003 it was decided to ignore maintenance scheduling for this study.

Removing maintenance schedules from the reliability model generally shifts the highest risk hours to those with highest demand. This relationship can be seen in Figure 3.1, which shows the ranking of the top 500 load hours of the year and the hourly LOLP in each of those hours. As seen in the figure, there is a much higher relative risk during the peak hours than other times.

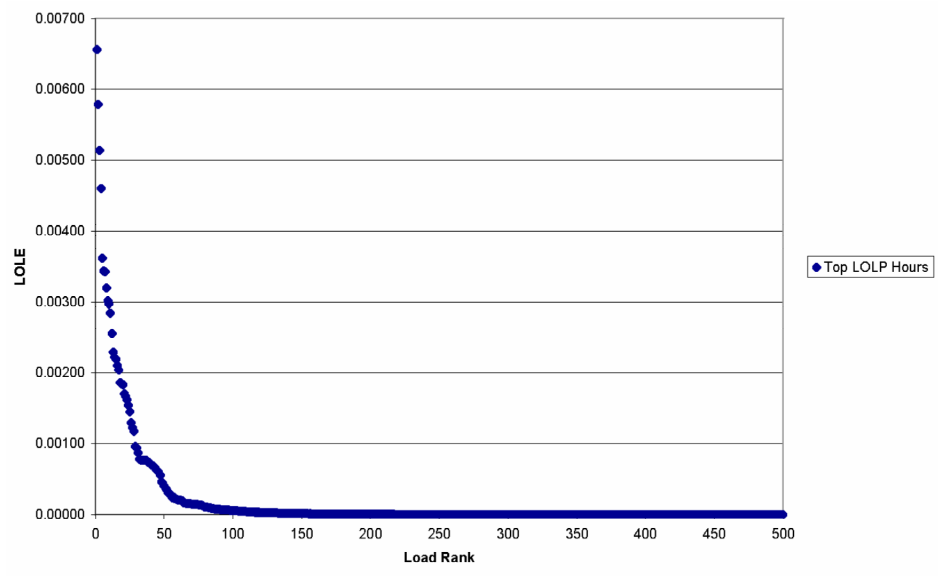

Figure 3.1 Reliability and top 500 hours ranked by load/LOLP.

Figure 3.2 is a LOLE duration curve, showing the number of hours that the system is at alternative risk levels. Aside from the logarithmic scale of this second graph, the overall shapes of the curves are similar, illustrating the relationship between risk and load.

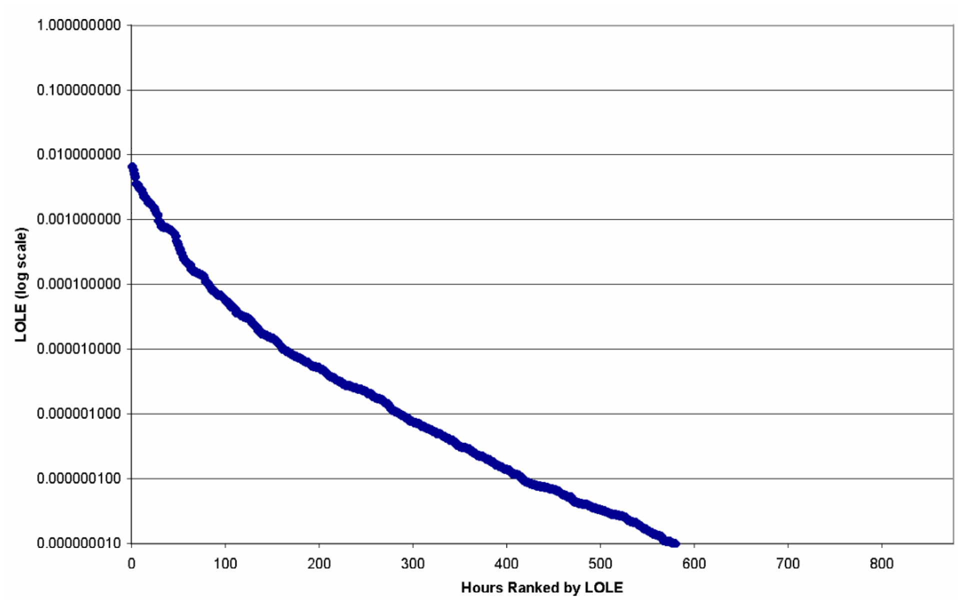

Figure 3.2 LOLE duration curve.

3.2.2 CONVENTIONAL PLANT BASELINE CAPACITY CREDIT

For a conventional generator the primary determinants of ELCC are the rated capacity of the plant and its forced outage rate. For a generator of a given size, higher forced outage rates will reduce its load carrying capability and lower forced outage rates will increase its ELCC. Although most conventional units have relatively low forced outage rates, some older units are not as reliable.

Even a generator with a very high forced outage rate will make at least a minimal contribution to system reliability and will have a relatively low ELCC.

Figure 3.3 illustrates how ELCC varies at higher forced outage rates. The graph is based on the California system, adding a generic conventional unit sized at 100 MW, and alternative forced outage rates ranging from 10% to 90% in increments of 10%. Because the baseline plant for the ELCC calculation has a 4% forced outage rate and 7.6% maintenance rate, the generic 100 MW unit achieves a 100 MW ELCC at a 10% forced outage rate with respect to the reference plant. As the forced outage rate increases, the ELCC declines, reaching a low of 10.4 MW at a forced outage rate of 90%. Although it is difficult to see in the graph, the ELCC as a percent of rated capacity is not the same as the product of the forced outage rate and plant capacity. For example, at a 40% forced outage rate the ELCC of the generic plant is 62.5 MW.

Intermittent generators such as wind plants generally would be expected to provide a similar ELCC as a conventional generator with a relatively high forced outage rate, whereas intermittent units such as solar would be expected to have higher ELCC rates. Renewable generators that behave more like conventional units, such as biomass and geothermal, would likely have ELCC ratings that are near their respective rated capacity values. Of course other factors such as fuel supply constraints could have a significant negative impact on the ELCC of these plants.

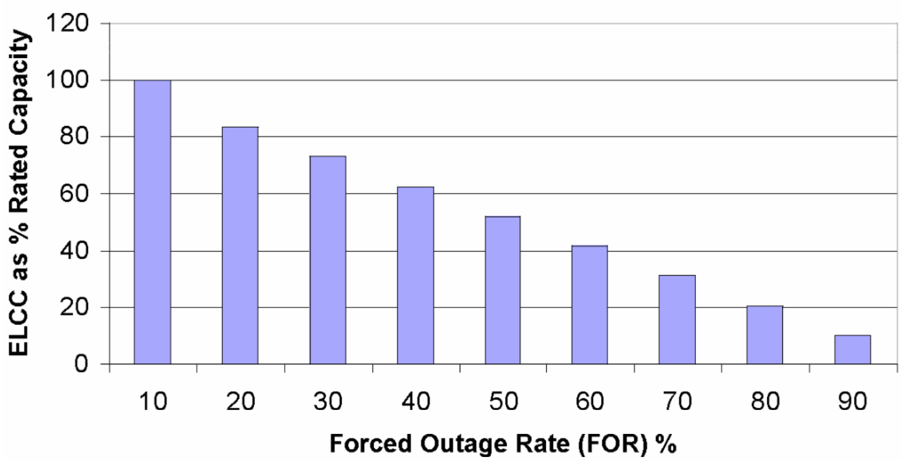

Figure 3.3 ELCC of generic 100 MW conventional plant as a function of Forced Outage Rate (FOR).

3.2.3 REPRESENTATION OF INTERMITTENT RENEWABLE GENERATORS IN THE RELIABILITY MODEL

Intermittent renewable resources cannot be represented in a reliability model in the same way as a conventional generator because it is important to retain the time-varying nature of the resource in the model. Although there are several approaches that have been applied, a method that is based on the actual statistical distribution of intermittent output over the relevant time period is the most appropriate for reliability modeling.[11] In this way the resource is treated in a similar manner as a multi-block generator, with different availability rates for different levels of output. For intermittent generators, this approach is expanded to allow for the changing statistical distribution through time. For studies that focus on operating reliability, it is often desirable to obtain a fine granularity of the intermittent distribution, using as many discrete distributions as possible. For example, using actual hourly wind generation over a one-year period, we could calculate 24 distributions per week, each one representing a specific hour of the day. For a longer-range planning study, it would be reasonable to calculate these distributions over longer time periods.

The results that were presented at the Public Workshop on September 12, 2003[12] utilized a large number of discrete statistical distributions for the initial reliability analysis. A number of participants suggested an approach that would recognize inter-annual variability in both loads and renewable resources. Although a multi-year analysis is beyond the scope of Phase I, the reliability modeling was altered so that the intermittent renewable data distributions could be combined to represent a typical month. Although this does not fully recognize inter-annual variations, it is a step in that direction. We anticipate that additional annual data will be analyzed in Phase II of this project.

For the intermittent generators we calculated the ELCC as a percent of the maximum capacity attained over the year. For existing resources this means that some installed capacity may not be accounted for in the calculation. However, the rated capacity for some wind plants often does not take account of the generating capacity that is no longer available. These older turbines have often not been properly maintained and are no longer useful. Therefore the ELCC as calculated as a percentage of maximum capacity is probably representative of the existing fleet capability, and this is likely to be true for turbines that are based on modern technology as we move to the future.

3.2.4 RENEWABLE RESOURCE CAPACITY CREDITS

3.2.4.1 Biomass

Because biomass resources behave much like conventional generators, their ELCC is primarily a function of the rated capacity of the plant and forced outage rate, and is therefore not related to the timing of capacity deliveries to the grid. Figure 3.4 shows the results of a series of model runs used to find the geothermal ELCC.

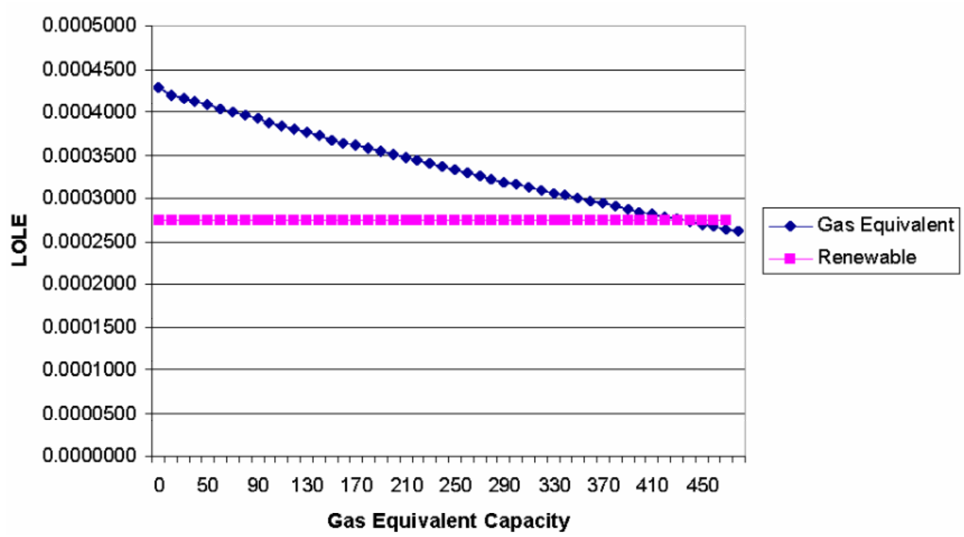

Figure 3.4 Biomass reliability curve.

The baseline model run was made with all renewable resources in the generating mix. To calculate the biomass ELCC, biomass was removed and the annual reliability was calculated. The result appears as the vertical distance between the two curves in the figure when gas capacity is zero. This vertical distance is the increase in annual risk that occurs when biomass is removed. To find ELCC, the model is rerun for increasing increments of the gas benchmark unit until the two curves cross.

This means that the baseline reliability has been restored, but by using the gas plant instead of the biomass generation. The gas capacity that is required to achieve this level of reliability is the ELCC capacity of biomass, expressed as the gas equivalent. The diagram indicates that the biomass ELCC is 97.8% of its rated capacity.

3.2.4.2 Geothermal

The data used for the geothermal resources were obtained from the CaISO PI system. This hourly data represents actual geothermal output over the year. Because the water supply is limited at this site, the generation is constrained because of the limited steam production. The units at this site also respond to dispatch instructions from the CaISO, although the output generally does not vary significantly from hour to hour. For this study it was not possible to tell whether constrained output from the units occurred because of steam constraints or dispatch instructions, although information provided by the CaISO indicates that the steam constraint has a significant impact on the units operation. But because these units also respond to dispatch instruction, the ELCC of the geothermal units may be somewhat understated when using the actual hourly production data. Figure 3.5 shows the results using this data and the ELCC was 73.6%. The reliability modeling for this geothermal case utilized the same approach as was used for the intermittent renewable generators so that the hourly data could be fully used in the analysis.

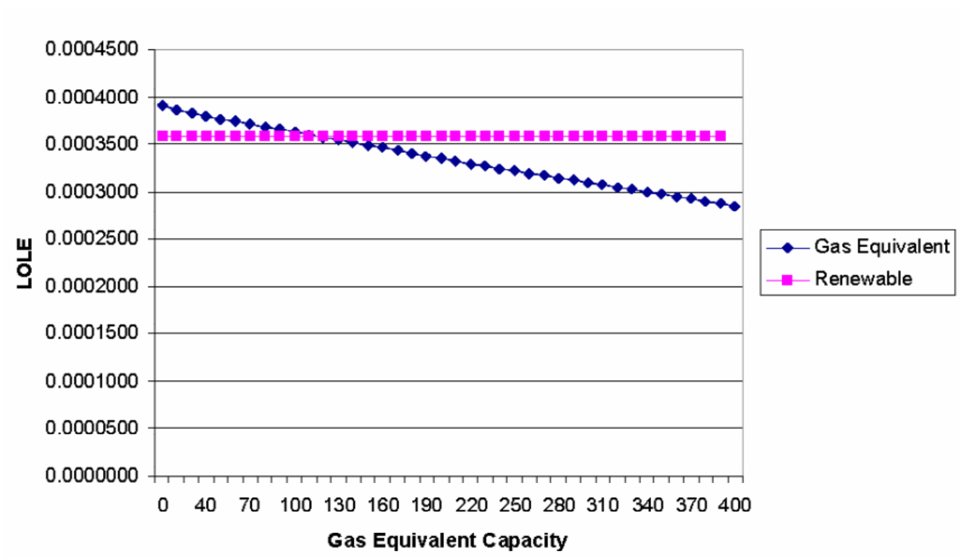

Figure 3.5 Geothermal reliability curve including steam constraint and dispatch.

We also looked at an unconstrained geothermal case to illustrate the potential differences between the actual geothermal production and potential production, absent a steam constraint as shown in Figure 3.6. Because geothermal units are very reliable, their ELCC exceeds that of the reference gas plant, as indicated by the ELCC of 102.3%.

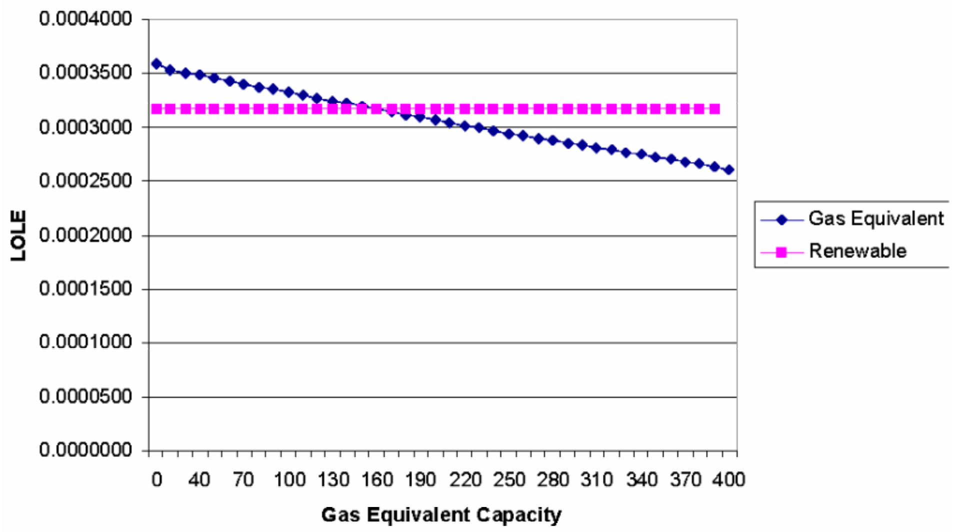

Figure 3.6 Geothermal reliability curve absent steam constraint.

3.2.4.3 Solar

Even though it is intermittent, solar generation can be highly correlated with load because the typical diurnal load shape is sometimes nearly matched by the solar generation profile. However, there can be times that clouds reduce solar output during the very hot weather that induces high power demand. The solar data from the CaISO PI system was used to calculate the ELCC, and appears in Figure 3.7. The results indicate an ELCC of 56.6% of rated capacity.

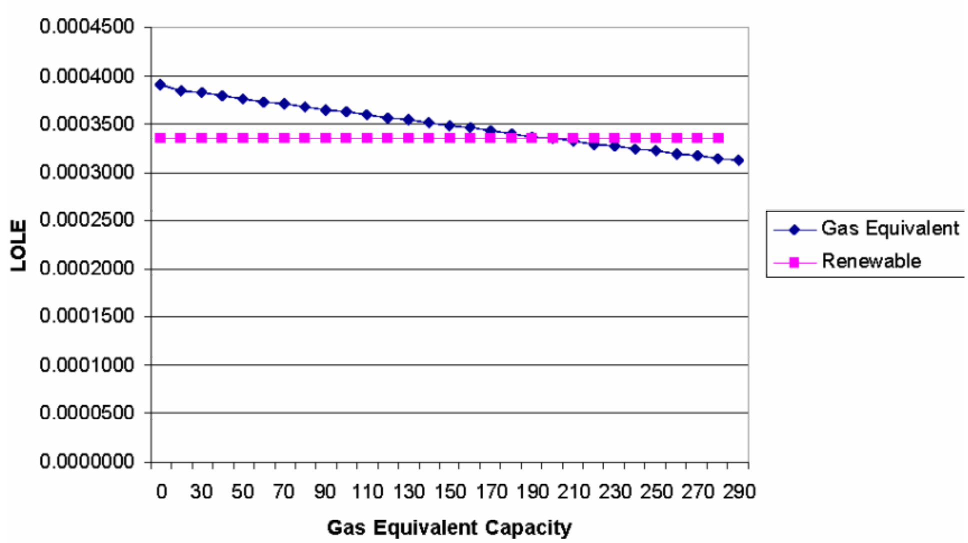

Figure 3.7 Solar reliability curve.

During the 12 September 2003 public workshop and the public draft review period of this report, several parties commented (see Appendix C) that the solar capacity credit value was lower than they expected. As shown in Figure 3.8, the correlation between solar generation and peak load hours generally appears to be high. However, visual inspection of the graph indicates that there is significant variability in solar output during the top 200 load hours.

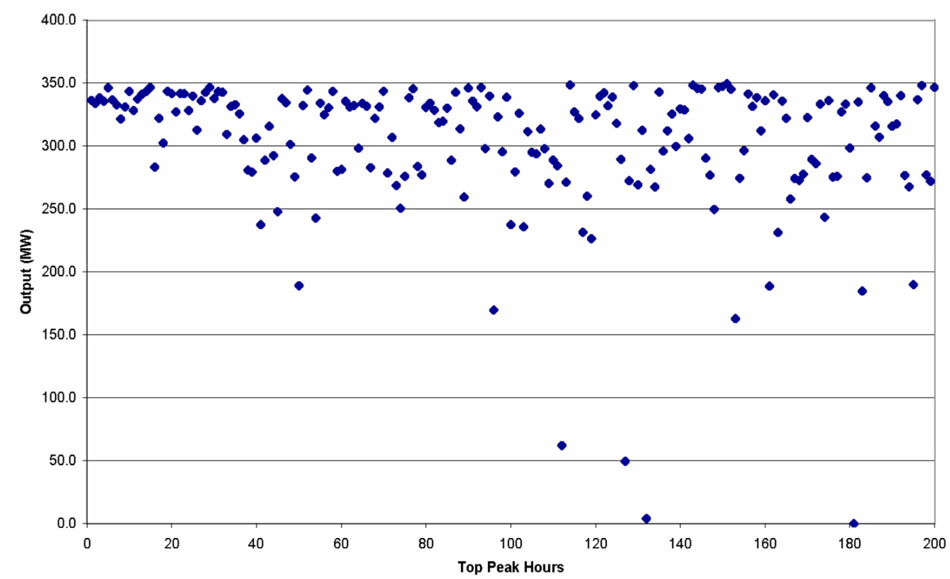

Figure 3.8 Solar output during the top 200 load hours.

The capacity factor for the top 200 hours is 87%, but that doesn't tell the whole story. When we calculate the standard deviation of solar output over the top 200 hours we find it is 54.6 MW, and the resulting coefficient of variation is 18%. This variation is significant, and reduces the ELCC of the solar generation. During these relatively high risk hours, there are times that solar output is significantly less than maximum output, and therefore does not contribute to risk reduction as much as if it maintained a constant output over the 200 hours.

Other possible causes for the deviation from expectations are discussed in Section C.1.1. Given the concerns presented in Appendix C, additional analysis of solar's ELCC is warranted.

3.2.4.4 Wind

The three wind resource areas were modeled separately for this study. It was not possible to obtain dis-aggregate wind production data, but we don't believe that is a significant limitation of these results. The ELCC of a given resource area reflects the combined reliability impact of the generators at that general location. We would expect that some individual wind farms contribute more to reliability (and therefore have a higher ELCC) than others (with a lower ELCC). As this project moves forward, it will be important to be able to quantify expected ELCC or capacity credit for individual bidders, but that will be addressed in Phases II and III of this study.

The results from the three wind resource areas appear in Figure 3.9 through Figure 3.11. As indicated, wind in the Altamont area contributed ELCC of 26.0%, San Gorgonio 23.9%, and Tehachapi 22.0%.

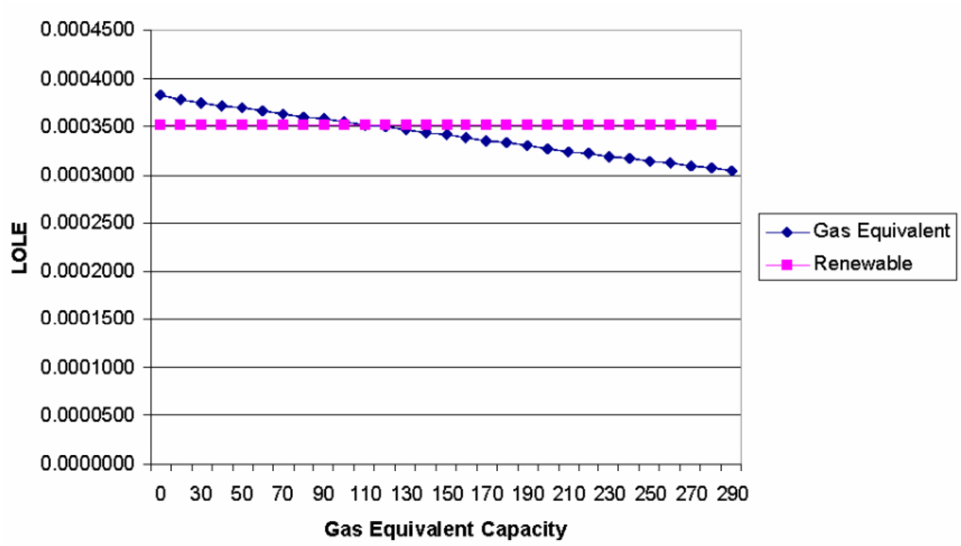

Figure 3.9 Wind reliability curve in Altamont region.

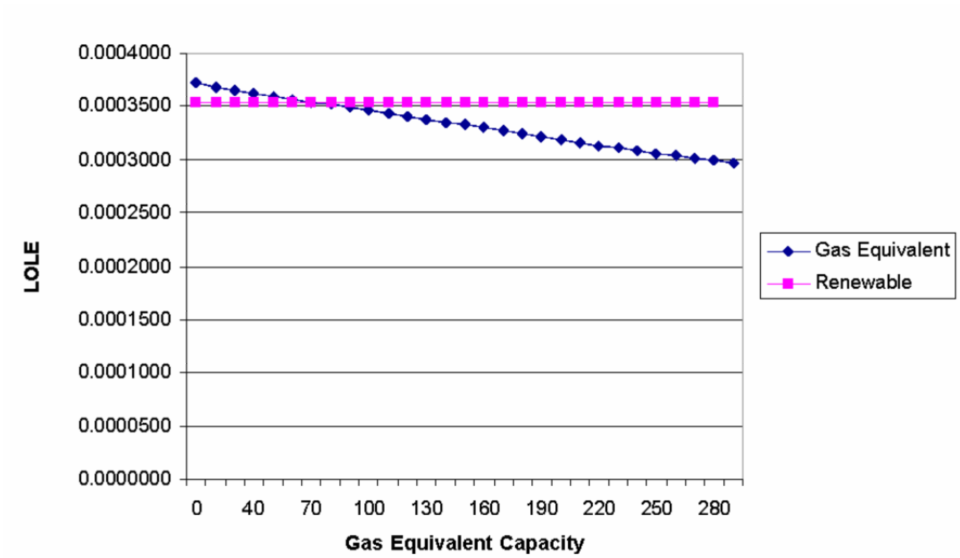

Figure 3.10 Wind reliability curve in San Gorgonio region.

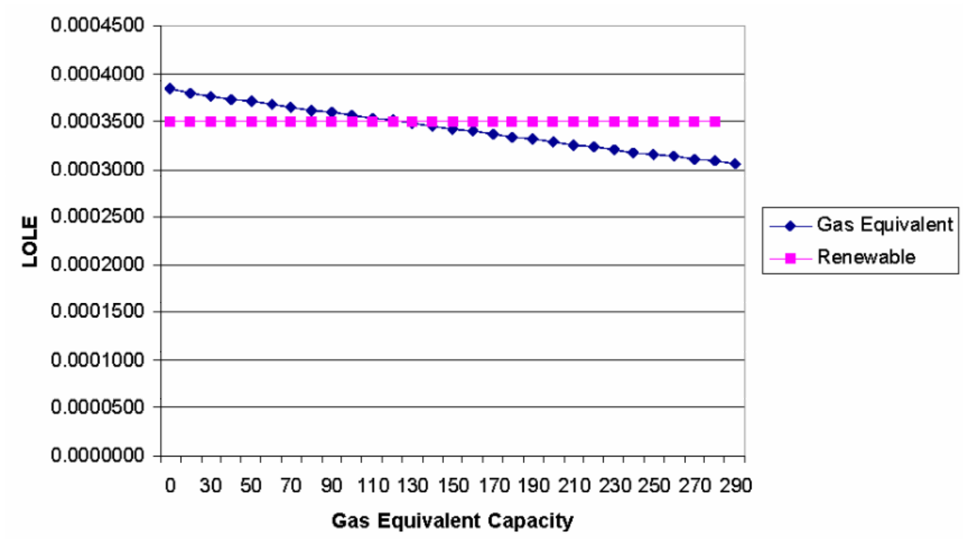

Figure 3.11 Wind reliability curve in Tehachapi region.

3.2.4.5 Intermittent Capacity Credit Summary

Table 3.1 and Figure 3.12 show the capacity credit calculated from each of the renewable technologies.

Table 3.1 Capacity credit results

Resource	Relative Capacity Credit
Medium Gas	100.0%
Biomass	97.8%
Geothermal (constrained)	73.6%
Geothermal (unconstrained)	102.3%
Solar	56.6%
Wind (Altamont)	26.0%
Wind (San Gorgonio)	23.9%
Wind (Tehachapi)	22.0%

As expected, the biomass and geothermal resources have high ELCC values (in the absence of fuel or other constraints) because they behave most like conventional resources. Wind ELCC is significantly lower than the other resources, but shows that wind can help reduce system risk, albeit by a modest amount when compared to other resource types. The wind ELCC values are consistent with what we would find for a conventional unit with a very high forced outage rate—about 75%—as indicated in Figure 3.3. As discussed above in Section 3.2.4.3 and in Appendix C, further analysis of the solar ELCC value is necessary.

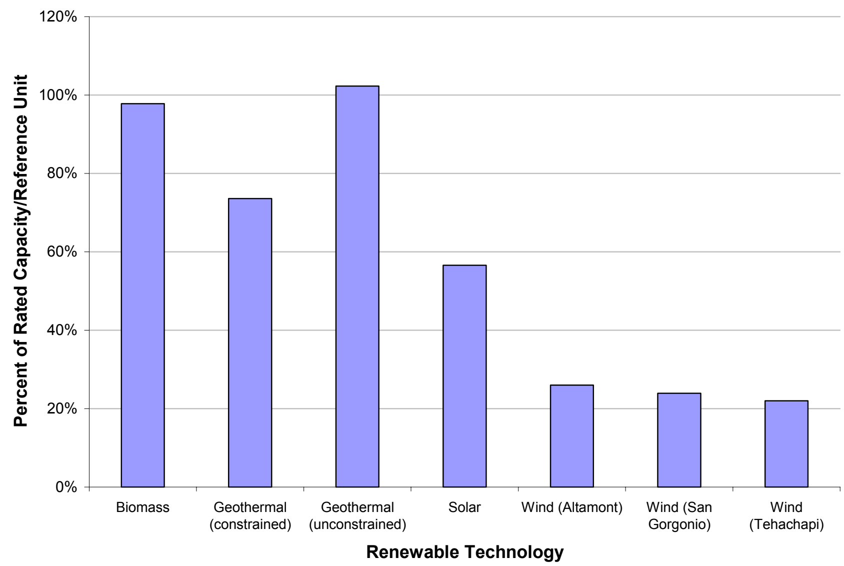

Figure 3.12 ELCC results for various renewable technologies.

3.2.5 SIMPLER METHODS FOR CALCULATING CAPACITY CREDIT

One of the goals of this study is to suggest simpler, transparent methods to calculate the capacity credit of renewable resources. Phase I has begun that process, but additional work needs to occur in Phase II because approaches used in prior analyses do not appear to work well for California.

One technique that has appeared promising in other studies involved the calculation of the capacity factor of the renewable resource over several peak periods, with the goal of approximating the ELCC by using the much simpler capacity factor calculation. To benchmark this method, a full complement of ELCC calculations and capacity factor calculations must be performed so that a reasonable comparison can be made. Once the benchmark has been satisfactorily performed, the capacity factor over a selected number of top load hours can be used to approximate the capacity credit. Figure 3.13 illustrates some results from this method, using wind and utility data from the Great Plains.

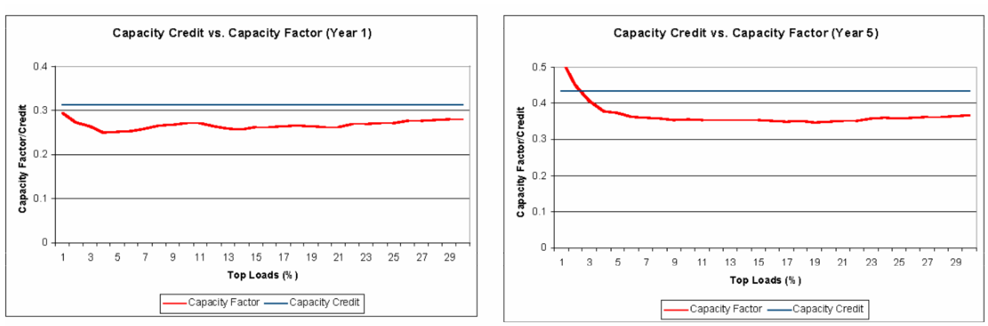

Figure 3.13 Example of simple methods to calculate ELCC.

Although imperfect, these examples show that the capacity factor can approximate the ELCC of a wind plant, and this approximation appears to be relatively close when the top 10% of load hours are used for the capacity factor calculation.

The results from California suggest that this particular approximation method won't work. Figure 3.14 shows the application of the method to solar generation. The graph extends to the top 10% of hourly loads for the year, ranked by LOLP (there is no significant difference in ranking by LOLP or load). For each of the 876 hours in the graph, the *cumulative* capacity factor was calculated. For example, at hour 100 the solar capacity factor is calculated by using the top 100 LOLP hours.

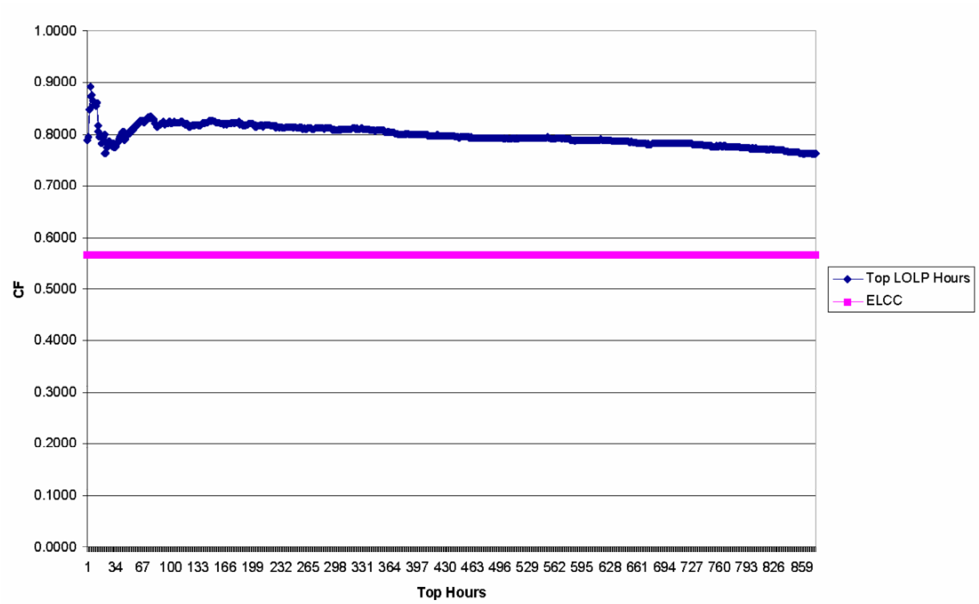

Figure 3.14 Solar cumulative capacity factor.

The solid line shows the ELCC. Clearly there is no particular relationship between the ELCC and capacity factor. This lack of correspondence is caused by the relatively high variability of the solar resource during the peak/high risk period, as discussed above in the context of Figure 3.8. This lack of correspondence also extends to the wind resources at each location. Figures 3.15, 3.16, and 3.17 show the results.

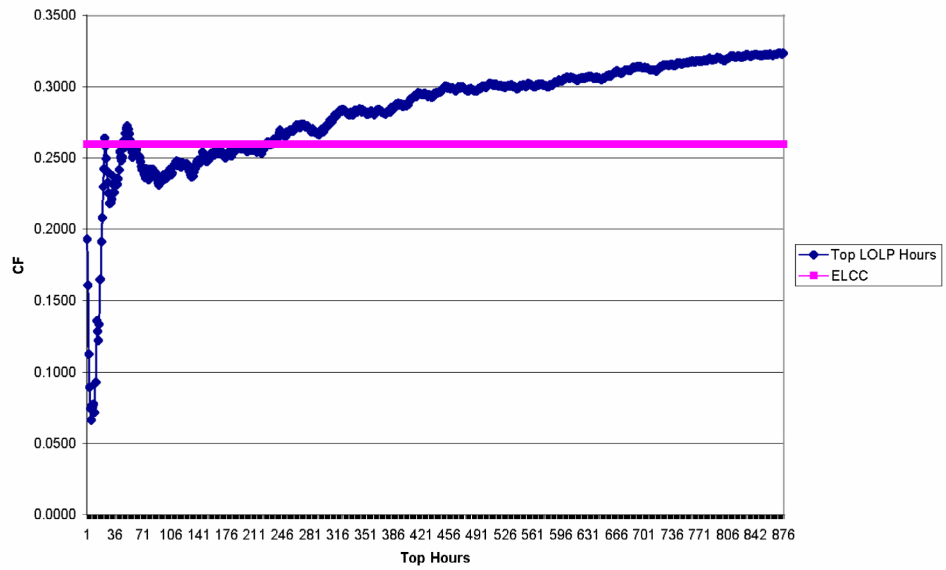

Figure 3.15 Wind cumulative capacity factor in Altamont region.

In the case of the wind resources, the lack of correspondence is compounded by the low wind output during the highest risk hours. The combination of low wind output during some of the high-risk hours has a significant downward effect on the ELCC of the respective wind plant. It is clear that using the capacity factor as an estimator for capacity credit over the top 5%-10% of LOLP-ranked hours would significantly overstate the ELCC proxy.

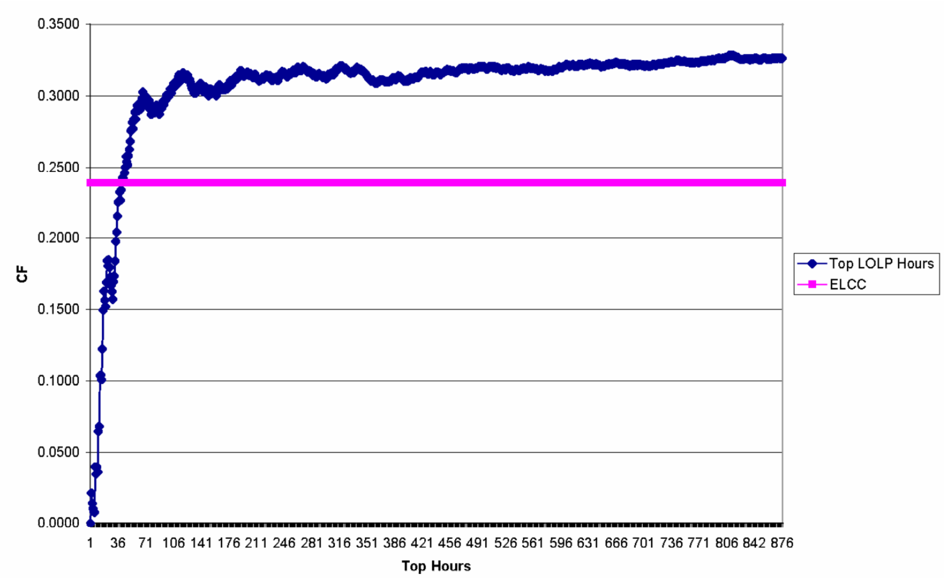

Figure 3.16 Wind capacity factor in San Gorgonio region.

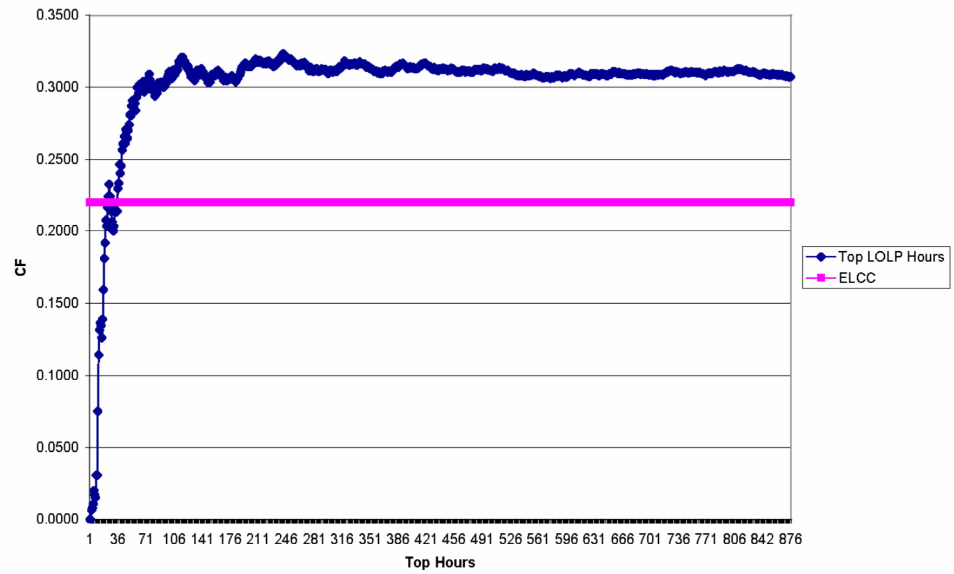

Figure 3.17 Wind capacity factor in San Gorgonio region.

Although the ELCC line is cut by the cumulative capacity factor curve, it is unlikely that the number of hours at which this intersection occurs would be consistent from year to year. This instability would make this estimator a poor indicator of future performance of a wind plant, and an unreliability indicator of the capacity contribution of the wind plant.

For the Altamont site, the correspondence is somewhat better. The curves intersect at approximately 232 hours, approximately the top 2.6% of high-risk hours. Although it would be premature to draw a conclusion that this approach will provide robust results at Altamont, it is an indication that the simpler approach *may* be appropriate for Altamont. As part of the Phase II analysis, load and resource data from other years will be analyzed so that a simple, transparent method for assessing renewable capacity credit can be developed.

3.3 Capacity Analysis Recommendations

3.3.1 CAPACITY CREDIT FOR RENEWABLE BIDS

The capacity analysis done in Phase I can be used to help rank potential bids from biomass, geothermal, and wind renewable energy providers. Solar requires additional study before any findings can be applied toward bid selection.

For biomass and geothermal resources, it will be important to ascertain that the expected fuel supply can be obtained over the life of the proposed project. This may be particularly important for geothermal resources that could be subject to future steam constrains, such as those presently experienced at the Geysers. The commission may want to consider asking for an independent verification of such resource availability as part of the bid process.

Data from three wind resource areas were available for analysis in this study. Wind bidders from each of these areas would almost certainly be able to achieve at least the level of capacity credit as calculated using the ELCC methods because of the significant improvements in wind generating technology that have occurred in recent years. With the newer technology that is currently being installed at wind plants in the U.S., these technical improvements are improving the energy capture at lower wind speeds and at lower air densities. Although it is likely that newer technology near the existing resource areas will have higher ELCC, a more complete assessment of this issue is incomplete at present. Initial data from the Solano County installation suggests that additional energy capture can also result from good site location. Until further analysis can be done, wind bidders could be expected to provide the ELCC levels at the respective resources areas analyzed for this Phase I report.

3.3.2 APPLICABILITY OF RESULTS FOR INCREASING RENEWABLE PENETRATION LEVELS

To help determine the sensitivity of the ELCC results to higher renewable penetrations, a set of model runs were conducted at double the current level of renewable resources. To accomplish this, the hourly intermittent output levels were doubled for each wind site, solar, and the hourly geothermal time series. For the unconstrained geothermal and biomass cases, the capacity rating of the respective resource was doubled. The combined renewable resources were added to the base case, and each renewable resource ELCC was estimated, one at a time using the same procedure as the base case.

There was a slight decline in the ELCC of each wind resource area. Altamont wind declined from 26% to 24%, San Gorgonio declined from 24.9% to 22.9%, and Tehachapi declined from 22.0% to 19.9%. Solar declined slightly to 55.3%, and there were no changes in geothermal or biomass.

It is important to interpret these results in the context of potential renewable bids in the near future. First, it is widely known that scaling up existing intermittent renewable plants, as done for this increasing penetration analysis, overstates the variability of the output and contributes to reliability on a declining marginal basis. Adding capacity during the same hours will cause a drop in the potential reliability benefit of the resource, because reliability in those hours has already improved somewhat. Second, existing wind technology has improved significantly beyond the technology that is currently in widespread use in California. Improvements in control algorithms, lower-speed turbines, and blade-pitching to compensate for lower air density at higher temperatures are the most notable examples of these improvements. Although Phase II will allow us to do a better job of quantifying these variables, we believe that these improvements, along with different wind resource characteristics and better siting, imply that the Phase I capacity results represent robust, conservative values for at least a doubling of renewable capacity in California.

3.3.3 PHASE II ANALYSIS

Preliminary discussion with the CEC indicates that the market simulation model used at the Commission does not calculate hourly reliability indices. If this is indeed the case, benchmarking this model with the reliability/capacity credit runs described in this report may not be possible. Because of the complexity of production simulation and reliability models, it can be very time consuming to calibrate two models to obtain similar base case results. However, we will look into the possibility of applying another model to the capacity results.

Since one of the objectives of the RPS Integration Study is to help evaluate bids from a potentially large number of renewable energy suppliers, it is imperative that the final product of this study has the capability of differentiating between multiple bidders. The Phase I work did not have access to disaggregate renewable generation data. However, we don't believe that to be a significant impediment to the goal of providing a method to distinguish between the capacity values of multiple bidders. The next two phases of this project will develop a relatively simple, transparent method to approximate the ELCC of bidders with different resource characteristics. The development of a bid evaluation method for capacity value will be based on an approximation to ELCC based on the timing of resource output (in the case of intermittent renewable generators) relative to hours of potentially high risk. The reader should *not* conclude that because the Phase I report does not distinguish between individual generators, that the final method also won't distinguish between them.

Depending on data availability, Phase II will examine a sampling of disaggregate renewable generators to determine their ELCC value individually. We don't anticipate performing this analysis on every existing renewable generator because that appears to be beyond the scope of this project. Instead, we will select among individual generators so that we can fairly represent locational and resource differences. The results from this part of the study will be used to help derive a usable metric to evaluate bids from individual renewable generators.

Renewable generator technology has changed significantly since many of the existing units were installed in California. Because the primary goal of this project is to capture the likely impacts and costs of new renewable generators in future capacity and energy acquisitions, we will examine the likely impact of these technical changes in Phase II.

As we stated in the Public Workshop on September 12, 2003, it is hard to imagine that a serious intermittent renewable energy bid would be received without a serious data collection effort. However, if that were the case, we recommend the development of an appropriate number of "class average" capacity values. These would be applied to a bid based on the characteristics of the technology and location (and any other relevant data) similar to existing generator technologies and locations. However, if selected, we would recommend that actual payments to a generator (to be evaluated more fully in Phases II and III) should be based on *actual* performance once the project begins operation.

3.3.4 CAPACITY PAYMENTS

Our understanding is that a separate study is currently underway that will assess the value of capacity in the California market. As this work moves forward, the results will be incorporated into any capacity payment mechanism that would result from the work in Phases II and III of the RPS Integration Study.

3.3.5 MAINTENANCE IMPACTS ON RELIABILITY

We recommend that the Commission consider a separate study to determine the impact that maintenance schedules have on system risk as measured by LOLP or another similar reliability metric.

4 REGULATION COST ANALYSIS

Two methodologies for calculating regulation costs were reviewed by the Methods Group. One methodology, Method 1, developed by Brendan Kirby et al at Oak Ridge National Laboratory (ORNL), was selected as the primary basis of the study. The methodology and its results are described below. An alternative regulation analysis methodology (Method 2) was developed by Yuri Makarov at the CaISO during the course of the Phase I study. A preliminary discussion of Method 2 is presented in Section 4.4. The Method 2 Phase I results will be compared with the Method 1 results in the future.

4.1 Regulation Analysis Approach

4.1.1 DECOMPOSITION OF CONTROL AREA LOADS

The regulation analysis methodology has been applied to a variety of other control areas to quantify the ancillary service impacts of loads and intermittent resources. It determines the regulation and load following impacts to the control area. These impacts are the result of fluctuations in aggregate load and/or uncontrolled generation that must be compensated. Once the requirements are quantified, the method then determines the costs incurred in terms of greater amounts of purchased regulating capacity and greater use of the short-term energy markets.

Loads within the control area can be decomposed into three elements (Figure 2.1). The first element is the initial load (base) of the scheduling period, 80 MW over the one hour period shown in this case. The second element is the trend (ramp) during the hour and from hour to hour (the morning pickup in this case); here that element increases from 0 MW at 7 a.m. to 18 MW at 8 a.m. The third element is the rapid fluctuations in load around the underlying trend; as shown here the fluctuations range over ±1 MW. Combined, the three elements yield a load that ranges from 79 to 98 MW during the hour.

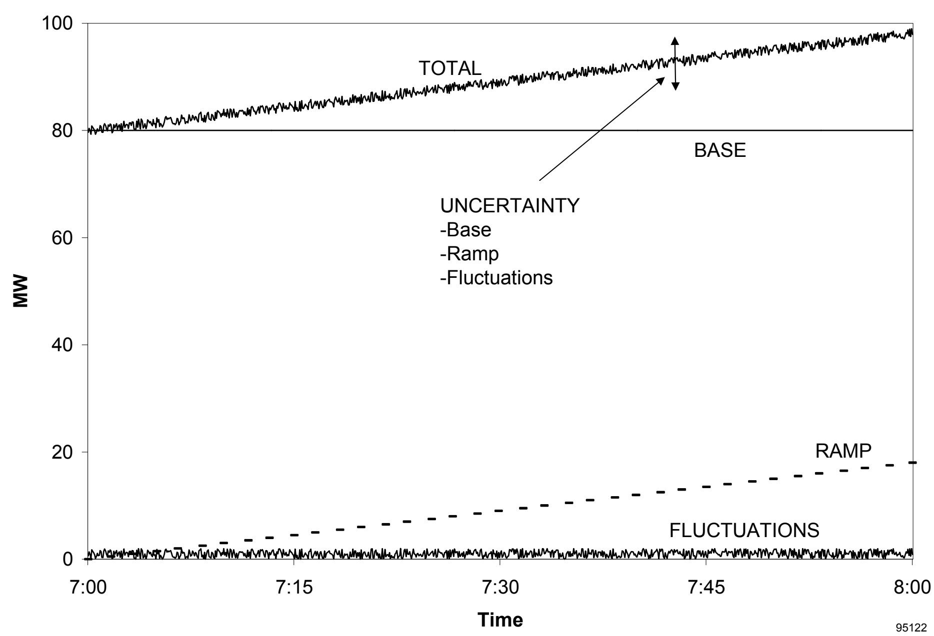

Figure 4.1 Decomposition of hypothetical weekday morning load.

The system responses to the second and third components are called load following and regulation. These two services ensure that, under normal operating conditions, a control area is able to balance generation to load. The two services are briefly defined[13,14,15] as follows:

- *Regulation* is the use of online generating units that are equipped with automatic generation control (AGC) and that can change output quickly (MW/minute) to track the moment-to-moment fluctuations in customer loads and to correct for the unintended fluctuations in generation. In so doing, regulation helps to maintain interconnection frequency, manage differences between actual and scheduled power flows between control areas, and match generation to load within the control area. This service can be provided by any appropriately equipped generator that is connected to the grid and electrically close enough to the local control area that physical and economic transmission limitations do not prevent the importation of this power.

- *Load following* is the use of online generation equipment to track the intra- and inter-hour changes in customer loads. Load following differs from regulation in three important respects. First, it occurs over longer time intervals than does regulation, 10 minutes or more rather than minute to minute. Second, the load-following patterns of individual customers can be highly correlated with each other, whereas the regulation patterns are largely uncorrelated. Third, load-following changes are often predictable (e.g., because of the weather dependence of many loads) and have similar day-to-day patterns.

Assessing the individual customer, or renewable generator, contribution to the overall regulation requirement necessarily involves evaluating generation performance. A control area is not expected to perfectly match generation and load instantaneously. Rather, generation matches load with some time lag, and, therefore, generation matches load only approximately. Although the AGC systems at most utility control centers send raise and lower pulses to individual generators as frequently as every two or four seconds, generators do not follow such short-term load fluctuations. Our prior work[16] suggests that generation follows load at the one- to two-minute interval.

There is no hard-and-fast rule to define the temporal boundary between regulation and load following. If the time chosen for the split is too short (e.g., five minutes), too much of the fluctuations will appear as load following and not enough as regulation. If the boundary is too long (e.g., 60 minutes), too much of the fluctuations will show up as regulation and not enough as load following. But in each case, the total is unchanged and is captured by one or the other of these two services.

4.1.2 CALCULATION OF THE REGULATION COMPONENT

The regulation requirements of the CaISO system were analyzed and the impacts of individual uncontrolled generators on the total regulation requirement were determined utilizing a method developed by Oak Ridge National Laboratory (ORNL)[2]. This method has been used to analyze control area performance, individual loads, non-conforming loads, non-AGC generators, and wind plants for a number of utilities including: American Electric Power (AEP), Central & South West (CSW), NIPSCO, Bonneville Power Authority (BPA), Commonwealth Edison (ComEd), Pennsylvania-New Jersey-Maryland Interconnection (PJM), Alberta, New Brunswick, and Ontario Hydropower. Electrotek used the method in their analysis for Xcel[17], Great Rivers, and ERCOT.

Specifically, a 1-minute average energy data and a 15-minute rolling average were used to separate regulation from load following. The rolling average for each 1-minute interval was calculated as the mean value of the seven earlier values of the variable, the current value, and the subsequent seven values:

$$Load\ Following_t = Load_{estimated\text{-}t} = mean\ (L_{t-7}\ ,\ L_{t-6}\ ,\ \ldots\ ,\ L_t\ ,\ L_{t+1}\ ,\ \ldots\ ,\ L_{t+7}) \quad [4.1]$$

$$Regulation_t = Load_t - Load_{estimated\text{-}t} \quad [4.2]$$

This method is somewhat arbitrary and imperfect.[2] It is arbitrary in that the time-averaging period (15 minutes in this project) and the temporal aggregation of raw data (1 minute) cannot be predetermined. In principle, the control-area characteristics (dynamics of generation and load and the short-term energy market interval) should determine these two factors.[18] For this study the 15-minute rolling average was selected because it provides good temporal segregation and captures the characteristics of California's supplemental energy market.

The standard deviation of the 1 minute regulation values for total system load was calculated hourly as the metric for regulation performance. A utility typically carries about three standard deviations of regulating reserves to assure adequate CPS performance (see Appendix A).

4.1.3 SHORT TERM FORECAST VERSUS ROLLING AVERAGE

In practice, system operators cannot know future values of load. They generally produce short-term forecasts of these values to aid in generation-dispatch decisions. There are two problems with using short-term forecasts to separate regulation and load following. First, while aggregate load forecasts are typically well developed, short-term forecast methodologies for non-dispatchable conventional and renewable generators are not. The CaISO is currently developing an improved forecasting tool for wind, for example. Second, even when they are being used for operations the short-term forecast results for individual generators or loads are typically not saved. Finally, the rolling average has proven to be a reasonable analytical substitute in studying other control areas. The rolling average, like the system operator, is constantly moving the regulating units back to the center of their operating range. When consistent, robust short-term forecasts are available and verified for all of the renewable generation technologies, this analysis can be repeated without needing to use the rolling average.

The use of the rolling average rather than the short term forecasts can impact the allocation of variability between the regulation and load following services slightly. Significantly, the method assures that total variability is captured in one or the other service and that there is no double counting.

4.1.4 INDIVIDUAL RENEWABLE GENERATOR METRICS

Once the hourly regulation requirements for the entire system were determined, we calculated individual contributions to that total requirement. Regulation aggregation is nonlinear; there are strong aggregation benefits. It takes much less regulation effort to compensate for the total aggregation than it would take if each load or generator compensated for its regulation impact individually. While this is a great benefit it also means that there is no single "correct" method for allocating the reduced total regulation requirement among the individuals. An allocation method should:

- Recognize positive and negative correlations
- Be independent of sub-aggregations
- Be independent of the order in which loads or resources are added to the system
- Allow dis-aggregation of as many or few components as desired

The method presented here, and described more fully in Appendix B, meets these criteria. It was developed by ORNL to analyze the impacts of nonconforming loads on power system regulation. It works equally well when applied to non-dispatchable or uncontrolled generators.

With the ORNL method it is not necessary to know every individual's contribution to the overall requirement. Specific individuals' contributions can be calculated based upon the total requirement and the individuals' performance. Because regulation is the short, minute-to-minute fluctuations in load, the regulation component of each individual is often largely uncorrelated with those of other individuals. If each individual's fluctuations (represented by the standard deviation (σ_i) is completely independent of the remainder of the system, the total regulation requirement (σ_T) would equal:

$$\sigma_T = \sqrt{\sum \sigma_i^2} \qquad [4.3]$$

where *i* refers to an individual and *T* is the system total.

For the case of uncorrelated contributions, the share of regulation assigned to each individual is:

$$Share_i = \left(\frac{\sigma_i}{\sigma_T}\right)^2 \qquad [4.4]$$

The more general allocation method[2], developed by ORNL and presented in Equation 2.5 accommodates any degree of correlation and any number of individuals. This allocation method is more complex but no more data-intensive than the previous method. This method yields results that are independent of any sub-aggregations. In other words, the assignment of regulation to generator (or load) g_i is not dependent on whether g_i is billed for regulation independently of other non-AGC generators (or loads) or as part of a group. In addition, the allocation method rewards (pays) generators (or loads) that reduce the total regulation impact.

$$Share_i = \frac{\sigma_T^2 + \sigma_i^2 - \sigma_{T-i}^2}{2\sigma_T} \qquad [4.5]$$

The general allocation method (Equation 4.5) was used to analyze the impacts various individual renewable generators had on the overall system's regulation requirements.

Calculated hourly regulation requirements were compared with hourly regulation purchases by the CaISO and hourly regulation self-provided by scheduling coordinators. Total regulation requirements were then allocated back to individuals. Hourly regulation costs were used to allocate the cost of regulation back to individuals. Total (i.e., procured + self-provided) pre-rational buyer regulation purchase data was not available, so the total regulation purchase values were determined by scaling with the ratio of total and procured regulation including the rational buyer. This guaranteed that the correct amount of regulation was accounted for. All of the CaISO's regulation requirements were allocated based upon the short-term variability impacts of the loads and renewable generators.

4.1.5 DATA REQUIREMENTS

Studying regulation requires one-minute, synchronized, integrated-energy, time series data for total control area load and the individual renewable resources of interest. The complete data list was:

One minute, synchronized, integrated-energy, time series data for:

- Total load
- Each renewable generator of interest

Experience has shown that it is also wise to perform an energy balance around the control area to assure data integrity. This required 1-minute data for total generation, net actual imports/exports, net scheduled imports/exports, system frequency (and the frequency bias), and ACE. The complete data list is:

One minute, synchronized, integrated-energy, time series data for:

- Total generation
- Net actual imports/exports
- Net scheduled imports/exports
- Area control error (ACE)
- Frequency (and frequency bias) – often provided as a deviation from scheduled frequency

Regulation analysis requires only one data element, plus one for each renewable generator of interest, each minute. Verifying data integrity requires an additional five data elements each minute.

The CaISO runs hourly markets for regulation up and regulation down. Price and quantity data from these markets were used to determine impacts on the quantity of regulating resources procured and the cost of the additional regulation. Scheduling coordinators are also allowed to self-provide regulation. The amount of self-provided regulation was added to the amount of purchased regulation to obtain the total regulation amount. There is no price associated with self-provided regulation so the market price of the purchased regulation for the same hour was used to calculate the total dollar value of regulation for each hour.

- Hourly regulation-up price
- Hourly regulation-down price
- Hourly MW of regulation-up procured (hour ahead and real-time)
- Hourly MW of regulation-down procured (hour ahead and real-time)
- Hourly MW of regulation-up self-provided
- Hourly MW of regulation-down self-provided

The amount of data that was collected and analyzed is a practical tradeoff and one complete year of data (525,600 minutes) was used for the Phase I analysis.

4.1.6 STEP-BY-STEP ANALYSIS METHODOLOGY

The following is a step-by-step listing of the regulation analysis methodology which was applied to each of the eligible renewable technologies. Inputs are explicitly listed if they are raw data or if they are not output generated in a previous step.

1. Verify data consistency by looking at total system inflows, outflows, generation, and load.

$$ACE(t) = [NI_A(t) - NI_S(t)] - 10\beta[(F_A(t) - F_S(t)] - I_{ME}(t) \quad [4.6]$$

$$NI_A(t) = G(t) - L(t) \quad [4.7]$$

Table 4.1 Verify data consistency

Inputs

	Data description		Units	Sampling rate
a.	L	total actual system load	MW	1 minute
b.	G	total actual system generation	MW	1 minute
c.	F_A	actual system frequency	Hz	1 minute
d.	F_S	scheduled system frequency	Hz	1 minute
e.	ACE	area control error	MW	1 minute
f.	NI_A	actual net tie flows	MW	1 minute
g.	NI_S	scheduled net tie flows	MW	1 minute
h.	β	control area frequency bias	$\text{MW}/0.1\text{ Hz}$	1 minute

2. Calculate 15 minute rolling average to use as a surrogate for the short term forecast.

$$L_{s_2}(t) = \overline{L_{15}}(t) = \frac{\sum_{x=-7\text{ min}}^{7\text{ min}} L\,(t+x)}{15} \qquad [4.8]$$

$$g_{i,s_2}(t) = \overline{g_{i,15}}(t) = \frac{\sum_{x=-7\text{ min}}^{7\text{ min}} g_i(t+x)}{15} \qquad [4.9]$$

Table 4.2 Estimate short term forecast from rolling average surrogate

Inputs

	Data description		Units	Sampling rate
a.	L	total system load	MW	1 minute
b.	g_B	biomass generation	MW	1 minute
c.	g_G	geothermal generation	MW	1 minute
d.	g_{ST}	solar generation	MW	1 minute
e.	g_W	wind generation	MW	1 minute
f.	g_C	sample conventional generation	MW	1 minute

Outputs

	Data description		Units	Sampling rate
a.	L_{ave}	short term load forecast	MW	1 minute

b.	$g_{B,ave}$	short term forecast of biomass generation	MW	1 minute
c.	$g_{G,ave}$	short term forecast of geothermal generation	MW	1 minute
d.	$g_{S,ave}$	short term forecast of solar generation	MW	1 minute
e.	$g_{W,ave}$	short term forecast of wind generation	MW	1 minute
f.	$g_{C,ave}$	short term forecast of sample conventional generation	MW	1 minute

3. Calculate the raw regulation component by subtracting the short term forecast from the actual data.

$$r_L(t) = L(t) - L_{ave}(t) \quad [4.10]$$

$$r_i(t) = g_i(t) - g_{i,ave}(t) \quad [4.11]$$

Table 4.3 Calculate regulation component by subtracting short term forecast

Outputs

	Data description		Units	Sampling rate
a.	r_L	regulation component of total system load	MW	1 minute
b.	r_B	regulation component of biomass generator(s)	MW	1 minute
c.	r_G	regulation component of geothermal generator(s)	MW	1 minute
d.	r_S	regulation component of solar generator(s)	MW	1 minute
e.	r_W	regulation component of wind generator(s)	MW	1 minute
f.	r_C	regulation component of sample non-controlled conventional generator(s)	MW	1 minute

4. Calculate the difference between the regulation component of the resource of interest and the regulation component of the total system load. The difference is the total system regulation requirement if the resource of interest was not present.

$$\Delta r_i(t) = r_L(t) - r_i(t) \quad [4.12]$$

Table 4.4 Calculate total system regulation less resource of interest

Outputs

	Data description		Units	Sampling rate
a.	Δr_B	total system regulation without biomass generator(s)	MW	1 minute
b.	Δr_G	total system regulation without geothermal	MW	1 minute

		generator(s)		
c.	Δr_{ST}	total system regulation without solar generator(s)	MW	1 minute
d.	Δr_{W}	total system regulation without wind generator(s)	MW	1 minute
e.	Δr_{C}	total system regulation without sample conventional generator(s)	MW	1 minute

5. Calculate the hourly standard deviation of the regulation values determined in the previous two steps.

$$\sigma_T(t) = \underset{x=0\to59\,\mathrm{min}}{\sigma}\left(r_L\ (t+x)\right) \tag{4.13}$$

$$\sigma_i(t) = \underset{x=0\to59\,\mathrm{min}}{\sigma}\left(r_i(t+x)\right) \tag{4.14}$$

$$\sigma_{T-i}(t) = \underset{x=0\to59\,\mathrm{min}}{\sigma}\left(\Delta r_i(t+x)\right) \tag{4.15}$$

Table 4.5 Calculate statistical metrics of regulation from existing data

Outputs

	Data description		Units	Sampling rate
a.	σ_T	standard deviation of regulation component of total system load	MW	1 hour
b.	σ_B	standard deviation of regulation component of biomass generator(s)	MW	1 hour
c.	σ_G	standard deviation of regulation component of geothermal generator(s)	MW	1 hour
d.	σ_S	standard deviation of regulation component of solar generator(s)	MW	1 hour
e.	σ_W	standard deviation of regulation component of wind generator(s)	MW	1 hour
f.	σ_C	standard deviation of regulation component of sample non-controlled conventional generator(s)	MW	1 hour
g.	σ_{T-B}	standard deviation of regulation of system without biomass generator(s)	MW	1 hour
h.	σ_{T-G}	standard deviation of regulation of system without geothermal generator(s)	MW	1 hour
i.	σ_{T-S}	standard deviation of regulation of system without solar generator(s)	MW	1 hour
j.	σ_{T-W}	standard deviation of regulation of system without wind generator(s)	MW	1 hour
k.	σ_{T-C}	standard deviation of regulation of system without sample conventional generator(s)	MW	1 hour

6. Allocate the regulation share to the resource of interest.

$$\hat{R}_i(t) = Share_i(t) = \frac{\sigma_T^2(t) + \sigma_i^2(t) - \sigma_{T-i}^2(t)}{2\sigma_T(t)} \quad [4.16]$$

Table 4.6 Allocate regulation share for each generator type

Outputs

	Data description		Units	Sampling rate
a.	$\hat{R}_B$	regulation share of biomass generation	MW	1 hour
b.	$\hat{R}_G$	regulation share of geothermal generation	MW	1 hour
c.	$\hat{R}_S$	regulation share of solar thermal generation	MW	1 hour
d.	$\hat{R}_W$	regulation share of wind generation	MW	1 hour
e.	$\hat{R}_c$	regulation share of sample conventional generation	MW	1 hour

7. Determine the regulation requirement of each resource of interest. The relationship between the regulation share and regulation requirement is assumed to be the same as the relationship between the total regulation impact (σ_T) calculated above and the actual regulation that was acquired during the time period.

$$R_i(t) = \frac{\hat{R}_i(t) R_{actual}(t)}{\sigma_T(t)} \quad [4.17]$$

Table 4.7 Calculate actual regulation share for each generator type

Inputs

	Data description		Units	Sampling rate
a.	R_{actual}	actual regulation (purchased and self provided, up and down) market data	MW	1 hour

Outputs

	Data description		Units	Sampling rate
a.	R_B	regulation requirement of biomass generator(s)	MW	1 hour
b.	R_G	regulation requirement of geothermal generator(s)	MW	1 hour
c.	R_S	regulation requirement of solar generator(s)	MW	1 hour
d.	R_W	regulation requirement of wind	MW	1 hour

		generator(s)		
e.	R_C	regulation requirement of sample conventional generator(s)	MW	1 hour

8. Calculate actual hourly regulation cost by multiplying regulation requirement by hourly regulation cost. Calculate the change in cost that results from each renewable generator.

$$COST_R(t) = R_i(t) \cdot RATE_R(t) \qquad [4.18]$$

Table 4.8 Calculate actual regulation cost for each generator type

Inputs

	Data description		Units	Sampling rate
a.	$RATE_R$	actual regulation rate (up an down) market data	$/MW-hr	1 hour

Outputs

	Data description		Units	Sampling rate
a.	$COST_{R,B}$	regulation cost of biomass generator(s)	$	1 hour
b.	$COST_{R,G}$	regulation cost of geothermal generator(s)	$	1 hour
c.	$COST_{R,S}$	regulation cost of solar generator(s)	$	1 hour
d.	$COST_{R,W}$	regulation cost of wind generator(s)	$	1 hour
e.	$COST_{R,C}$	regulation cost of sample conventional generator(s)	$	1 hour

4.2 Regulation Cost Analysis Results

We applied the regulation cost analysis method to the CaISO system to analyze the impact existing renewable energy resources had on the overall system regulation requirements. We assume that the CaISO is currently purchasing the correct amount of regulation and appropriately controlling the system to achieve a good balance of cost and reliability performance. We allocated the amount and cost of regulation to the aggregated loads and selected renewable generators.

4.2.1 TOTAL LOAD REGULATION COST

The CaISO forecasts regulation requirements hourly and runs hourly regulation up and regulation down markets to meet those needs. Scheduling coordinators are allowed to self supply regulation, reducing the amount of regulation that the CaISO must purchase in the hourly markets. The CaISO purchased an average of 189 MW of up regulation and 186 MW of down regulation in 2002 for average prices of $12.50/MW-hr and $14.01/MW-hr respectively. The amounts purchased ranged between 0 and 510 MW for regulation up and between 0 and 484 MW for regulation down. The prices ranged from $0 to $56/MW-hr for regulation up and $1 to $88/MW-hr for regulation down. The total cost of purchased regulation was just over $46 million in 2002. With the California system load ranging between 18 and 42 GW and averaging nearly 27 GW, purchased regulation added nearly $0.20/MWh to the average price of electricity for California loads in 2002. Scheduling coordinators self-supplied an additional average 212 MW of up regulation and 237 MW in 2002. Valuing this contribution at the same hourly market clearing prices as that purchased by the CaISO adds $52 million to the cost of regulation for the CaISO system. The total cost of regulation was then just over $98 million, resulting in a $0.42/MWh adder to the average price of electricity for California loads for 2002 for regulation.

System energy and regulation requirements vary constantly. Figure 4.2 shows the total system load for four days in 2002.

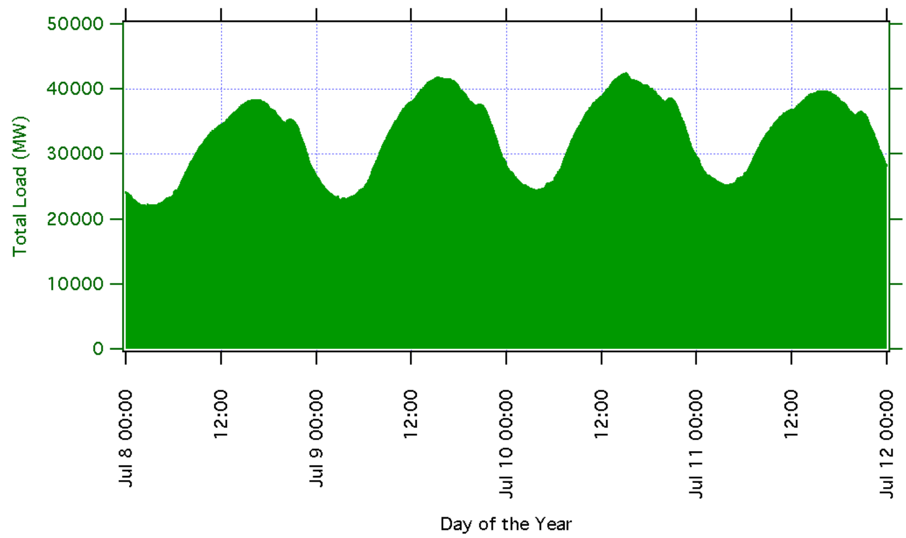

Figure 4.2 Total CaISO system load for four days in July.

Figure 4.3 and 4.4 show the total system load decomposed into the base energy, load following, and regulation components. Figures 4.5 and 4.6 provide a closer look at a single day. Though annual average results are presented in order to provide meaningful comparisons between various technologies the analysis was performed on one minute data for all 8760 hours in 2002.

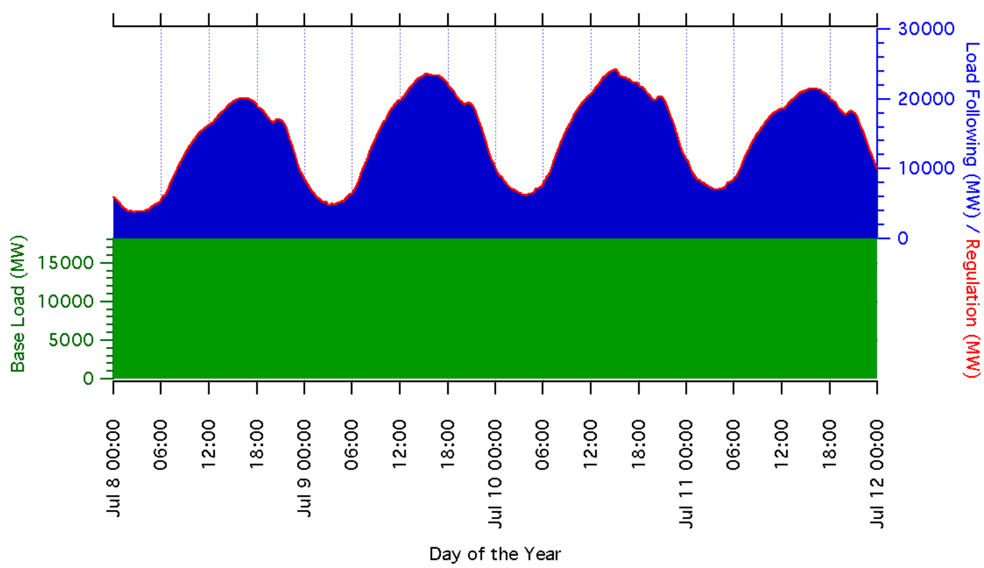

Figure 4.3 Total CalSO system load decomposed Into base energy, load following, and regulation.

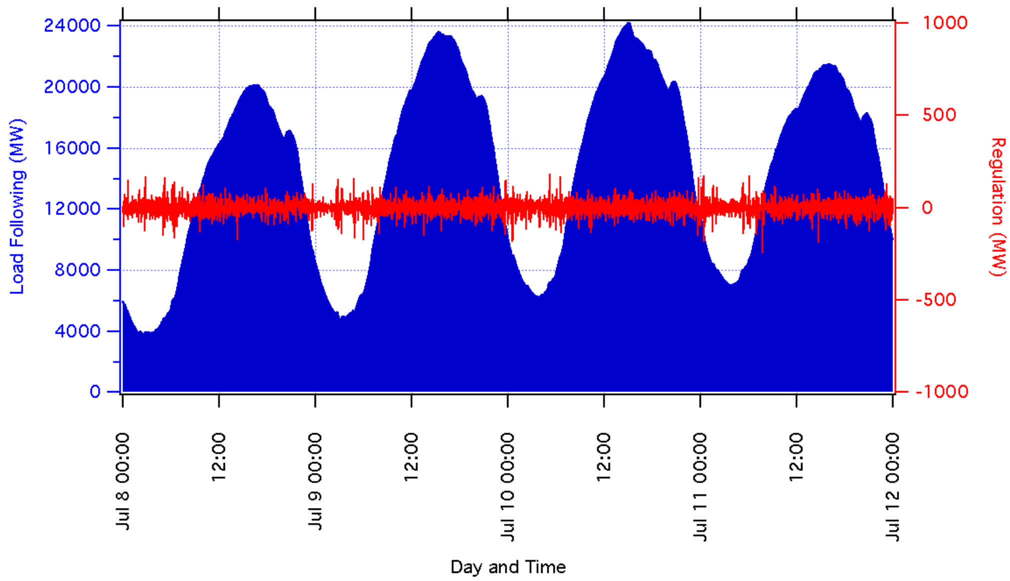

Figure 4.4 Regulation component segregated from load following and displayed on an expanded scale.

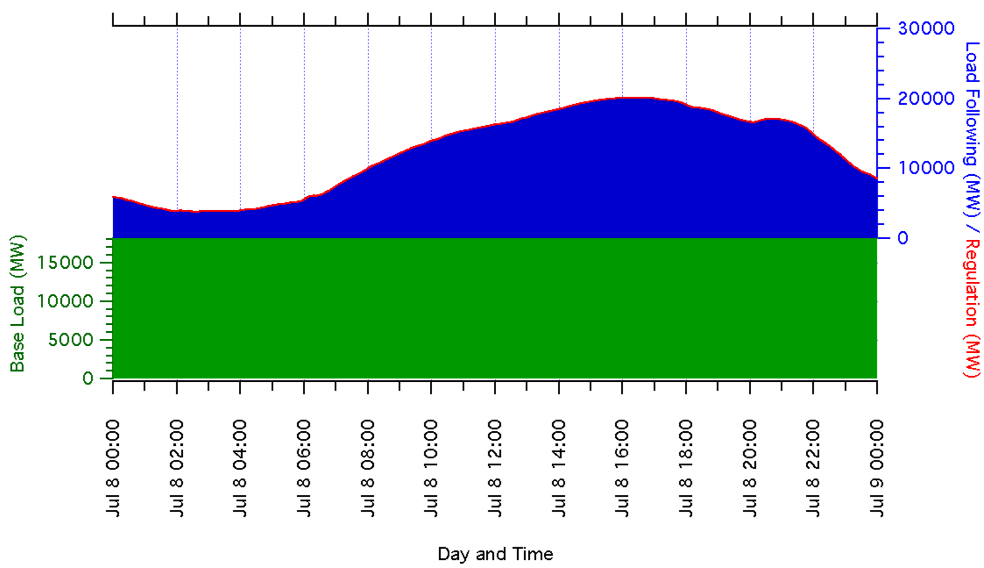

Figure 4.5 Expanded time scale shows the typical daily load pattern.

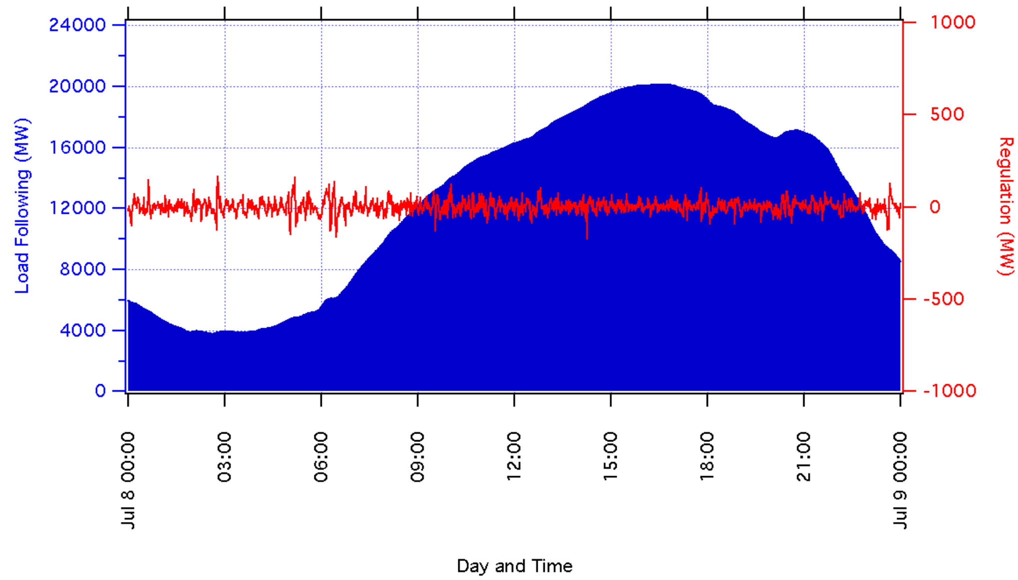

Figure 4.6 Regulation fluctuations are much faster and lower in magnitude than load following.

4.2.2 REGULATION COST COMPONENTS

The dominant cost for a generator in supplying regulation is the opportunity cost associated with maneuvering the generator in the energy market so that it has capacity available to sell in the regulation market. For example, a 300 MW generator with an energy production cost of $25/MWh would have to bid $20/MW-hr of up regulation if the energy market were clearing at $45/MWh. The $20/MW-hr is needed to make up for the profit that will be lost when the generator withholds capacity from the energy market in order to supply regulation.

The cost of down regulation is similarly based upon the relationship of the supplying generator and the energy market. When energy prices are low (typically at night) and generators are at minimum load, they incur a cost for running above minimum load in order to supply down regulation. For example, a generator with a 100 MW minimum load and an energy production cost of $25/MWh would have to bid $10/MW-hr of regulation if the energy market were clearing at $15/MWh because it will be loosing $10 for every MWh it must sell into the energy market to get its base operating point high enough to provide room to regulate down. This complex relationship between regulation costs and energy prices results in regulation prices being fairly volatile as shown in Figures 4.7. This graph presents average regulation price which was weighted by the actual reg-up and reg-down purchases. Figure 4.8 presents annual average regulation prices versus the time of day.

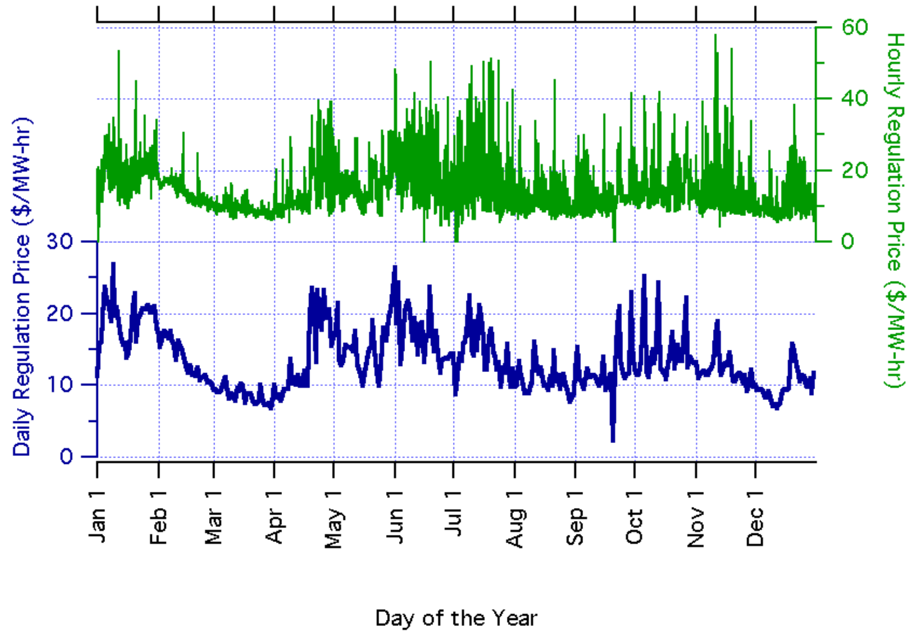

Figure 4.7 Daily weighted average regulation prices were volatile.

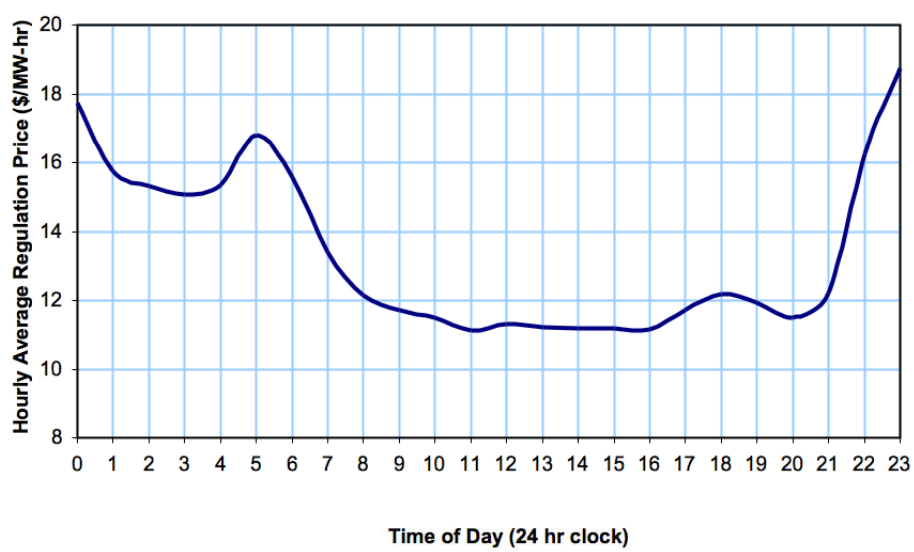

Figure 4.8 Hourly weighted average regulation prices were highest at night when supplying generators incur costs when moving up in order to create room to regulate down.

4.2.3 INDIVIDUAL RESOURCES

Regulation is used to compensate for minute-to-minute differences in the control area's aggregated generation and load. As such, regulation is procured and deployed on a control area wide basis. The behavior of individual loads and generators is important but individual behavior does not linearly impact overall requirements. Method 1 was designed to fairly allocate overall regulation requirements based upon the impact each individual has upon those requirements. The method automatically considers the minute-to-minute correlation between the individual and the overall system.

Individual movements that are highly correlated to the aggregate system either greatly help or greatly hurt regulation requirements. Generators on AGC, for example, deliberately correlate their minute-to-minute fluctuations opposite to the movements of the aggregated load in order reduce ACE and help CPS performance. Most loads' and non AGC generators' minute-to-minute fluctuations are not correlated with total load or each other; they are random. As such their impact on total system regulation requirements is greatly reduced. This is the great regulation benefit that comes from aggregating into large control areas.

A year of one minute data for total system load and a number of individual generators is too much to try to comprehend graphically. Still, it can be useful to examine some of the data directly before performing the regulation cost allocation analysis. Figure 4.9, for example, plots the outputs of two wind plants (Altamont and Tehachapi) against total system load. There does not appear to be much correlation. This does not help the wind plants in the energy market, where correlation with peak system loads and high prices would be good, but it does reduce the regulation and load following requirements.

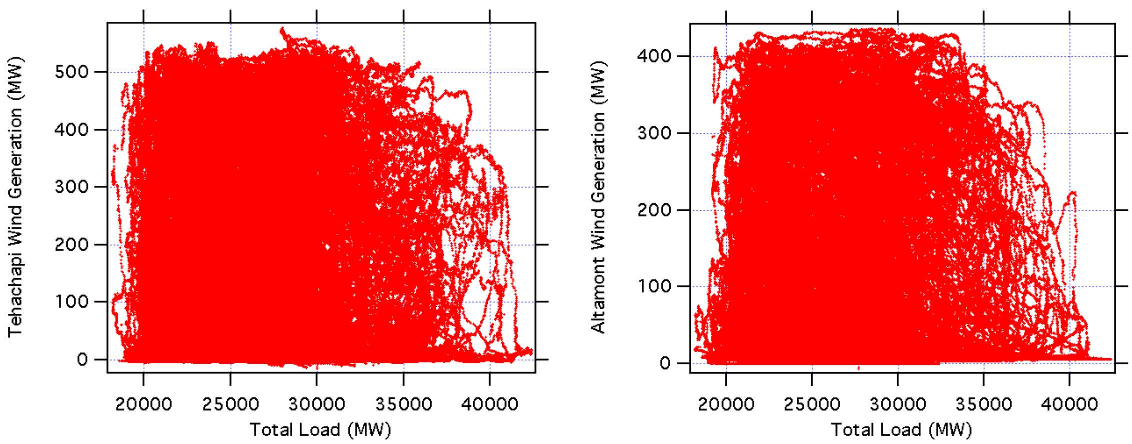

Figure 4.9 Correlation of wind generation and load for two regions.

Interestingly, Figure 4.10 shows that generation from the three largest wind resource areas show no correlation with each other. There appears to be significant geographic diversity in California for wind.

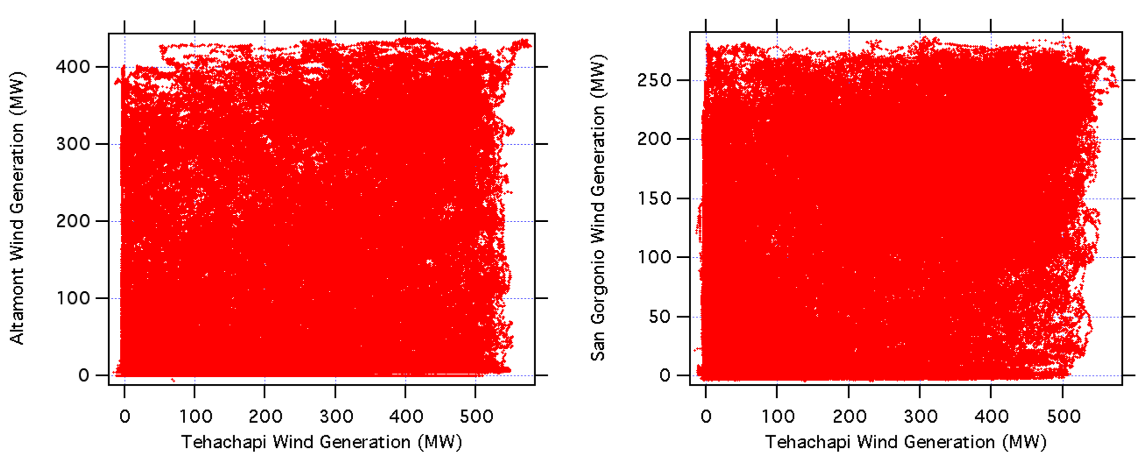

Figure 4.10 Correlation of wind generation among regions.

Figure 4.11 presents the Altamont wind plant output plotted against area control error (ACE). This also shows that the two are not correlated, as one might expect. This simply confirms that there is not a hidden connection between resource fluctuations and ACE that might adversely impact system performance. Figure 4.11 also provides a similar plot for the biomass plant. Here too there is no correlation evident between plant output and ACE. The teardrop shape results because the biomass plant spends little time at low output.

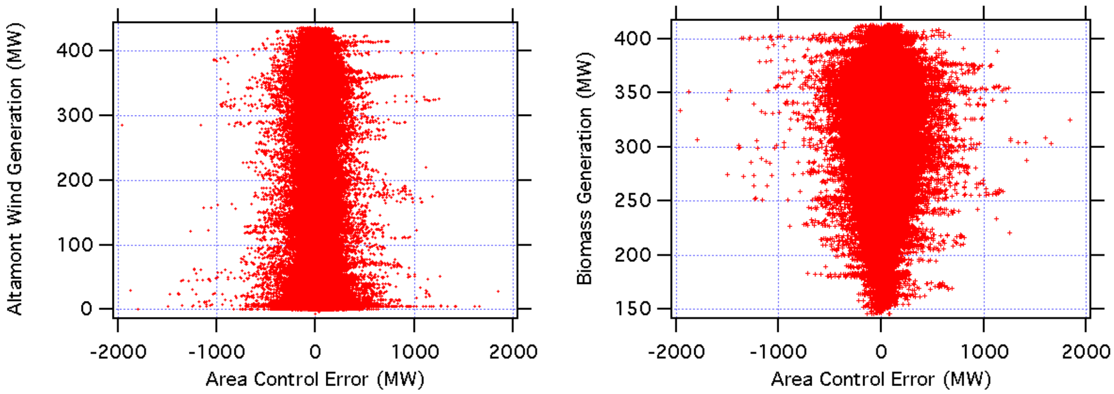

Figure 4.11 Correlation of wind and biomass Generation with ACE.

4.2.4 RESOURCE REGULATION COST

With one year of one minute data for total system load, seven renewable resources, and a medium size gas plant coupled with hourly regulation purchase and self-provision amounts and prices, we were able to allocate the cost of regulation. As described previously, we first separated the minute-to-minute regulation fluctuations from load following and base energy for the total load and each resource. We used the standard deviation as a good metric for variability. We chose hourly intervals because the regulation markets clear hourly with hourly prices and quantities. Total purchased and self-provided regulation and total purchased regulation cost were allocated to the total load and each of the individual resources hourly. The hourly calculations were summarized into annual averages and are presented in Table 4.9.

Table 4.9 Annual average allocation of purchased regulation costs.
Note: Negative numbers denote a cost while positive numbers indicate a value.

Resource	Regulation Cost ($/MWh or mills/kWh)	
	Procured	Total
Total Load	-0.20	-0.42
Medium Gas	0.04	0.08
Biomass	0.00	0.00
Geothermal	-0.05	-0.10
Solar	0.02	0.04
Wind (Altamont)	0.00	0.00
Wind (San Gorgonio)	-0.21	-0.46
Wind (Tehachapi)	-0.07	-0.17
Wind (Total)	-0.08	-0.17

Note: Use caution when applying $/MWh as a regulation cost metric.

Using $/MWh as a metric for regulation is both useful and dangerous. It is useful because what we really want to know is how much this ancillary service (something we are forced to buy but don't really want) adds to the cost of electricity (something that does useful work for us and we do want to purchase). In that sense a metric that is in the same units ($/MWh) as the commodity we are purchasing is very useful. It is dangerous because the amount of regulation required and the price have almost nothing to do with the amount of energy consumed or produced. The amount of regulation depends upon the short-term volatility of the generation or load, not the energy consumption or production. Use $/MWh in reference to regulation with great caution.

The sheer size of the load, when compared with the resources studied here, results in a calculated regulation cost for aggregated load that is essentially identical to the total system regulation cost. The results could have been different only if one or more of the other studied resources had a dramatic regulation impact. A few large arc furnaces, for example, would have sufficient impact to alter the cost of regulation for the rest of the load. None of the resources studied have that sort of regulation impact. In fact, the generating resources studied have quite minor impacts on total system regulation requirements. Scheduling coordinators self-provide about half of the required regulation resources. Consequently, the total cost calculated is about double the cost of purchased regulation alone.

An important note is that all of the results are quite small. They are, at best, at the edge of the error range for this data. We can clearly say that the impacts of the individual resources are not significantly larger than what is shown. However, it is difficult to have confidence in the precision of these small numbers. The CaISO PI data storage system was not designed to maintain this level of resolution for small fluctuations.

Given the caution on the precision of the results, it is not surprising that both the medium gas plant and the solar plant have slightly positive numbers. The daily solar cycle tends to follow the daily load pattern. This primarily helps with load following and improves the performance of the solar plant in the energy market. A small benefit also flows into the regulation performance. Similarly, the medium gas plant tends to chase the energy market price, helping load following. A small portion of this benefit also flows into regulation performance.

Not unexpectedly the wind plants impose a small regulation burden on the power system. This was expected because there is no apparent mechanism that would tie the wind plant performance to the power system's needs in the regulation time frame and result in a benefit like there is for solar plants or conventional plants that are following price signals. The regulation burden is low because there is also no mechanism that ties wind plant fluctuations to aggregate load fluctuations in a compounding way either. Wind and load minute-to-minute fluctuations appear to be uncorrelated. Hence they greatly benefit from aggregation. In aggregate, the wind regulation burden is lower (on an energy basis) than that imposed by loads. Interestingly there is a range of regulation performance that may be related to the geographic location of the wind plants.

The geothermal plant also shows a small regulation burden. Most of the time the geothermal plant has steady output and would be expected to impose little or no regulation burden. Examination of the time series data shows that there are times when output from the geothermal plant becomes somewhat erratic, possible explaining the slight regulation burden seen here.

The biomass plant output was steady and imposed no regulation burden.

4.3 Regulation Cost Analysis Recommendations

This preliminary analysis shows that there is little regulation impact imposed on the CaISO power system by the existing renewable resources. These results are sufficiently robust so that little impact should be expected if reasonable amounts of additional renewable resources are added to the system. The calculated impacts are close to the limits of the study accuracy.

It appears that different wind locations may have different regulation performance. This should be studied further. Similarly, the overall study accuracy should be refined. One minute data on total system load and each of the resources should be collected and saved at higher resolution than the current PI system accommodates. Analysis should be performed quarterly and annually to update this report.

4.4 Regulation Methodology Comparison

A second regulation valuation methodology, Method 2, was proposed in the 23 April 2003 report "California Renewables Portfolio Standard Renewable Generation Integration Analysis; Phase I: Analysis of Integration Costs for Existing Generation"[19] and at the 29 April 2003 CEC public workshop on RPS integration costs[20]. At the time of publication of this report, the Method 2 methodology development, implementation, and analysis runs are nearing completion. When the results and methodology are finalized, an addendum to this report will be published which will detail Method 2's finalized methodology and the results of the 2002 analysis.

Table 4.10 lists some of the conceptual similarities and differences in the way that Method 1 and Method 2 approach regulation analysis. A full comparison of the methodologies will be performed when the Method 2 analysis is completed.

Table 4.10 Conceptual overview of regulation methodologies.

Method 1	Method 2
Regulation is determined by analyzing the behavior of the power output of a given generator.	Regulation is determined by modeling the AGC generators which provide regulation services. The primary input to AGC generators and, consequently, this methodology, is ACE.
Regulation is independent of the generation schedule of a given generator. A rolling average of the generation is used in lieu of the generation schedule to separate out the regulation component of a generator.	Regulation is dependent on the generation schedule of a given generator.
Because the generation schedule is not explicitly used, very short term uninstructed deviations from schedule are not accounted for. However, by using a rolling average of generation as a surrogate, sustained deviations from schedule are properly assigned away from regulation.	Short term uninstructed deviations are accounted for. However, sustained deviations may be assigned to regulation instead of an energy imbalance service.
Regulation is independent of the real-time dispatch schedule.	Regulation is dependent on the real-time dispatch schedule.
Data required to determine the regulation requirement of a given resource are: total system load, generation of the resource of interest.	Data required to determine the regulation requirement of a given resource are: ACE, generation of the resource of interest, the real-time dispatch schedule, and a real-time schedule (short term forecast) for the generator. If the only real-time schedule available is an aggregate of which the generator is a constituent, then a "fair share assignment" must be made based on the average and RMS of the generation signal.
The regulation requirement of a given resource is determined by calculating the standard deviations of the fluctuations ("regulation components") of the total system load and generation of the resource of interest, then accounting for any correlation using a graphically intuitive allocation method.	The regulation requirement of a given resource is determined through a "variability metric" which uses the difference between the standard deviations of the system regulation requirement (set to be equal to ACE) and the system regulation requirement if the resource had been perfectly dispatched. The dispatch error is also a component of the metric.
Method 1 proposes that the aggregation of many generation and load resources reduces the amount of regulation required. Method 1 explicitly accounts for this benefit accordingly.	Method 2 accounts for correlation between load and generation (the aggregated system is considered through ACE), but does not explicitly address other aggregation benefits.
The final calculated regulation requirement reflects a scaling with actual purchased and self provided regulation amounts.	The final calculated regulation requirement reflects a scaling with a constant, the "confidence interval".
The regulation methodology potentially recognizes both costs and benefits to the system as a whole.	The regulation methodology potentially recognizes both costs and benefits to the system as a whole.
The methodology can be applied to any control area.	The methodology can be modified so that it can be applied to other control areas.
The regulation methodology including the allocation method has been published previously for peer review and has been adopted by some agencies.	The regulation methodology, variability metric, and fair share assignment method are newly developed and is scheduled for public presentation in October 2003.

5 LOAD FOLLOWING ANALYSIS

5.1 Decomposition of System Load

Previously in Section 4 we discussed how California's system loads and generation can be decomposed into three components: base load, load following, and regulation (Figure 5.1). The base load can be identified quite simply as the constant, unchanging portion. Load following refers to the intra- and inter-hour changes in load or generation. Load following differs from regulation in three important respects. First, it occurs over longer time intervals than does regulation, ten minutes or more rather than minute-to-minute. Second, the load following patterns of individual customers can be highly correlated with each other, whereas the regulation patterns are largely uncorrelated. Third, load following changes are often predictable and have similar day-to-day patterns.

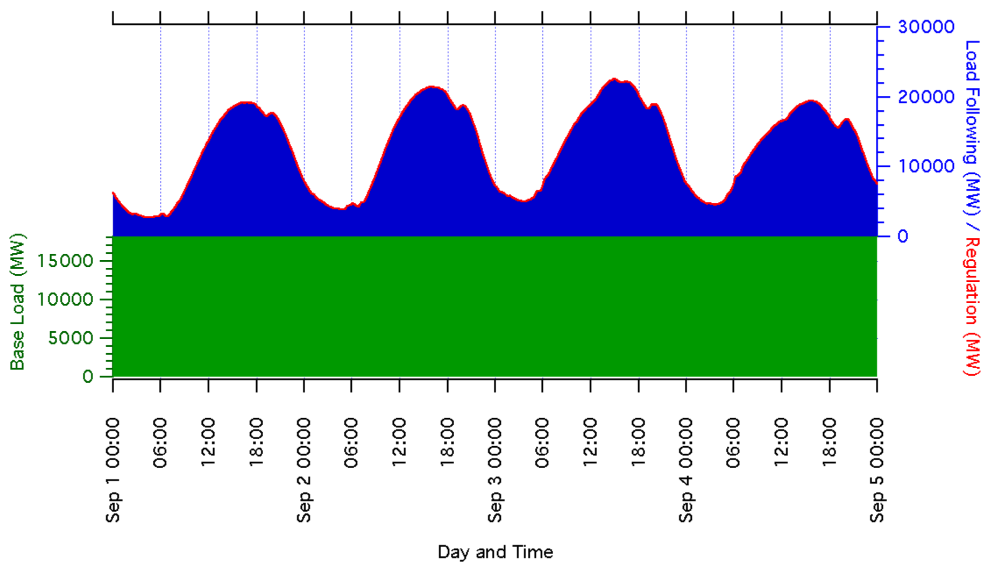

Figure 5.1 Decomposed System Load for Several September Days

Separating load following from regulation required that we define a temporal boundary between them. Selection of a particular temporal value will determine whether a change in load falls into one service category or the other. If the time chosen for the split is too short (e.g., five minutes), too much of the fluctuations will appear as load following and not enough as regulation. If the boundary is too long (e.g., 60 minutes), too much of the fluctuations will show up as regulation and not enough as load following. It is important to note that in either case the total is unchanged and is captured by one or the other of these two services.

Much of the energy required for load following is obtained from the CaISO hour ahead energy market. This market operates on a ten minute basis and participating generators can be dispatched up or down at the opening of each market cycle. The ten minute timeframe defined by CaISO for the supplemental energy market was used as the basis for selecting the temporal boundary between load following and regulation in this analysis. Load following was calculated as a rolling average of load (or generation) and a fifteen minute averaging period was selected to fully encompass each ten minute market cycle. The first step in decomposition was to subtract the base load of 18,149 MW, which was the minimum value for the analysis year. The second step was to calculate the load following portion using a fifteen minute rolling average. The third and last step was to subtract the load following component, leaving a remainder of rapid fluctuations defined as regulation. Figure 5.2 shows load following and regulation components of the total system load over four example days.

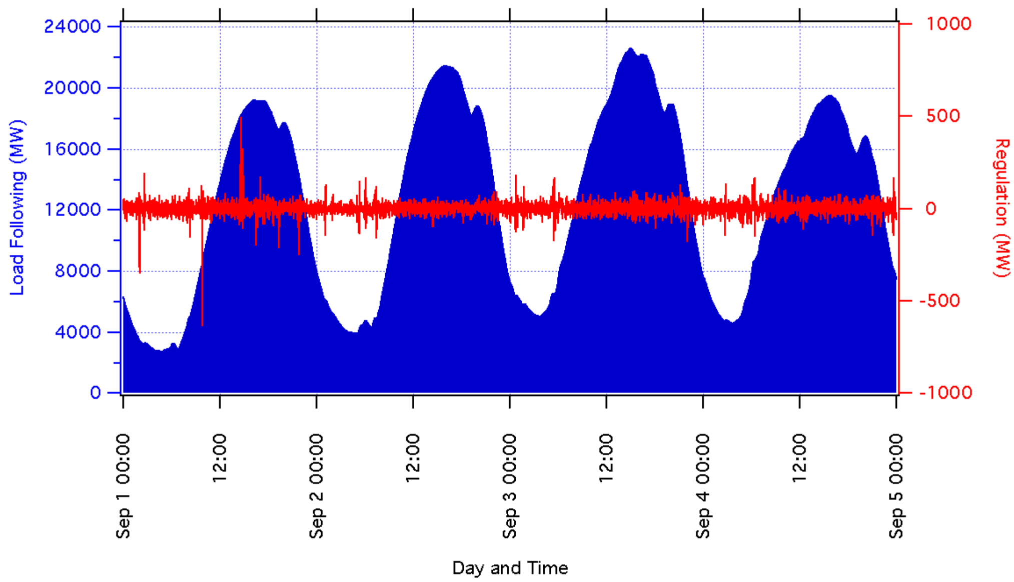

Figure 5.2 Load Following and Regulation for Several September Days

5.2 Load Following Analysis Approach

5.2.1 MARKET SETTLED COSTS

The hour ahead energy market is used to manage supplemental energy requirements. Since the CaISO energy market operates at the load following time scale, integration costs associated with the market were denoted as a load following integration costs. Participants in the CaISO hours ahead energy market submit bids for delivery of energy at the certain cost and at a certain time. The hour ahead market bids are due 150 minutes prior to the opening of each market cycle. At any given time the supplemental energy market generates a "stack" of bids from participating generators. Energy is purchased as needed to meet load demand by selecting generation resources from the bid stack. CaISO uses an automated system for selecting the most economic generators and calculating the dispatch instructions.

When the actual load demand differs from the scheduled generation an energy imbalance is created. The system operator can request incremental (INC) energy if more energy is needed, or decremental (DEC) energy when scheduled energy exceeds actual needs. CaISO defines instructed energy as the amount of energy which is expected to be produced above schedule or consumed below a specified schedule, as a result of following dispatch instructions. CaISO uses regulation generators (AGC) to compensate for instantaneous schedule deviations and ramping of dispatched units in real-time, and dispatches additional generating resources periodically to maintain desired regulation margins. Costs associated with short-term deviations from the schedule are captured by the regulation analysis, using the methodology documented in Section 3.

An automated system is used for balancing energy and selecting the most economic mix of generators. CaISO calls this system Balancing Energy and Ex-Post Pricing (BEEP), and the stack of participating bidders is called the BEEP stack. The amount of energy needed for each ten-minute interval is determined by the BEEP software, which determines the ten-minute list of dispatch instructions from the stack. Those instructions are reviewed and finalized before they are sent as dispatch instructions to the scheduling coordinators using the Automatic Dispatch System (ADS). The BEEP system is designed to adjust the generation mix during each ten-minute market cycle. This allows the system to compensate for scheduling deviations, re-center regulating units, and maintain the proper balance for its generators.

The hour ahead market pays generators for energy that is provided according to specified rules and procedures. CaISO has developed explicit market based methods for settlement (payments or charges) of energy deliveries for controllable generators (conventional, biomass, geothermal) and for intermittent resources (wind, solar, hydro). There are explicit settlement processes that can be applied to any generator who deviates from its schedule without specific dispatch instructions (uninstructed deviations). When a generator provides less energy than instructed, it is compensated for the amount of the instructed energy that was actually delivered. If a resource provides more energy than instructed (expected) the additional energy delivered is settled as uninstructed energy.

Since CaISO has rules and procedures in place to for settlement of imbalance energy caused by deviations from schedules and dispatch instruction, those costs are settled explicitly by the market and are not considered integration costs in this analysis. Integration costs as defined in this work are those costs implicitly borne by the system that are not allocated to a specific generator or load. Uninstructed energy is not considered an integration cost because it is settled explicitly by the market and any costs incurred by the system are charged to the specific generator.

5.2.2 LOAD FOLLOWING INTEGRATION COSTS

The load following analysis in this effort is focused on implicit costs associated with integration of renewable energy. Explicit, market settled costs were not considered. Integration of large amounts of renewable generators could potentially increase errors between scheduled and actual generation. Increases in scheduling error could potentially change the composition or size of the BEEP stack. If such a distortion of the bid stack occurred it could shift the market to marginal generators, whose costs were higher. That could increase the price of energy in the market and thus create implicit costs which were imposed on the system by the renewable generators. Large penetrations of renewable generators could also impact the size or composition of contingency reserves. The impact on contingency reserves will be considered in the next phase of work.

Our initial analysis in this phase focused on the potential impacts to the BEEP stack caused by renewable generation scheduling error. The methodology for the analysis was organized to determine if renewable generators had significant impacts on the systematic errors forecasts and schedules in the hour ahead market. The goal of the methodology was to analytically determine the impact of renewable generators on system scheduling error. If renewable generators created systematic errors that significantly increased the need for generation resources, then they could have a material effect on the composition of the BEEP stack or the ex-post price for energy.

The analysis methodology first determined system forecasting and scheduling errors for the benchmark case without renewable generators. CaISO prepares hour ahead forecasts of its generation requirements, which represent its best estimate of actual system load. The scheduling coordinators provide schedules which are designed to economically meet the forecast generation needs. The scheduling coordinators typically schedule significantly less generation than is needed for on-peak load and rely upon the hour ahead market to provide the balance. The difference between the forecast load and the scheduled load is defined as the scheduling bias. Forecast and scheduling errors in the benchmark case provide an indication of the variability inherent in operating the utility grid and are important because they define the normal range of errors without renewable generation impacts.

The next stage of the analysis was to calculate the scheduling errors for each renewable generator of interest. Worst case scheduling was used to estimate the impacts of the renewable generators. The analysis is therefore conservative. Bids for the hour ahead market are due 150 minutes prior to each market cycle. The scheduled output for the hour ahead market was defined by a simple persistence model, assuming that output 150 minutes in the future would be equal to output at the present time. For solar generators it was assumed that scheduled output was equal to what it had been on the previous day at the same time period.

The total forecasting error including the renewable resources was calculated by combining the system forecasting error (without renewables) with the additional scheduling error produced by the renewable resource in question. The forecasting error including renewable generators was then compared against the benchmark case and reviewed to identify the significant differences between them. The goal of this analysis was to determine if the renewable resources significantly changed the forecasting error and modified the generator bid stack.

5.2.3 STEP-BY-STEP ANALYSIS METHODOLOGY

The following is step-by-step listing of the load following analysis that was used.

1. Calculate the system forecasting error, defined as the difference between the hour ahead forecast prepared by CaISO and the actual system load (8760 hourly values).

$$e_{Forecast}(t) = L_{HA\_Forecast} - L_{Actual} \qquad [5.1]$$

2. Calculate the system scheduling error, defined as the difference between the hour ahead schedule provided by the scheduling coordinators and the actual system load (8760 hourly values).

$$e_{Schedule}(t) = L_{HA\_Schedule} - L_{Actual} \qquad [5.2]$$

3. Calculate the system scheduling bias, defined as the difference between the hour ahead forecast prepared by CaISO and the hour ahead schedule provided by the scheduling coordinators (8760 hourly values).

$$e_{Bias}(t) = L_{HA\_Forecast} - L_{HA\_Schedule} \qquad [5.3]$$

4. Calculate the hour ahead schedule of the generators of interest assuming a "worst-case" simple persistence model. The hour ahead schedule is prepared 150 minutes ahead of time. The persistence model assumes that generation at t+150 is equal to output at the present time, using averaged one minute data (8760 hourly values). For solar the model assumed that generation for a given time today would equal generation for the same time yesterday.

$$g_{i,HA}(t)=\frac{\sum_{x=1\,\text{min}}^{60\,\text{min}} g_i(t-150)}{60} \quad \text{and for solar} \quad g_{S,HA}(t)=\frac{\sum_{x=1\,\text{min}}^{60\,\text{min}} g_i(t-1440)}{60} \qquad [5.4]$$

where :

g_i is actual generation, and

$g_{i,HA}$ is the hour ahead schedule

Table 5.1 Calculate Hour Ahead Schedule for Each Resource

Inputs

	Data description		Units	Sampling rate
a.	g_B	biomass generation	MW	1 hour
b.	g_G	geothermal generation	MW	1 hour
c.	g_S	solar generation	MW	1 hour
d.	g_W	wind generation	MW	1 hour
e.	g_C	generation of sample conventional generator(s)	MW	1 hour

Outputs

	Data description		Units	Sampling rate
a.	$g_{B,HA}$	hour ahead schedule of biomass generation	MW	1 hour
b.	$g_{G,HA}$	hour ahead schedule of geothermal generation	MW	1 hour
c.	$g_{S,HA}$	hour ahead schedule of solar generation	MW	1 hour
d.	$g_{W,HA}$	hour ahead schedule of wind generation	MW	1 hour
e.	$g_{C,HA}$	hour ahead schedule of generation of sample conventional generator(s)	MW	1 hour

5. Calculate the scheduling error for resource of interest. The scheduling error is defined to be the difference between the hour ahead schedule and the 15 minute rolling average value. The scheduling error is an hourly average of one minute data (8760 hourly values).

$$e_i(t)=\frac{\sum_{x=1\text{min}}^{60\,\text{min}}\left[g_{i,HA}(t+x)-g_{i,ave}(t+x)\right]}{60} \qquad [5.5]$$

Table 5.2 Calculate the Resource Scheduling Error

Inputs

	Data description		Units	Sampling rate
b.	$g_{B,ave}$	average biomass generation	MW	1 minute

c.	$g_{G,ave}$	average geothermal generation	MW	1 minute
d.	$g_{S,ave}$	average solar generation	MW	1 minute
e.	$g_{W,ave}$	average wind generation	MW	1 minute
f.	$g_{C,ave}$	average generation of sample conventional generator(s)	MW	1 minute

Outputs

	Data description		Units	Sampling rate
b.	e_B	scheduling error for biomass generator(s)	MWh	1 hour
c.	e_G	scheduling error for geothermal generator(s)	MWh	1 hour
d.	e_S	scheduling error for solar generator(s)	MWh	1 hour
e.	e_W	scheduling error for of wind generator(s)	MWh	1 hour
f.	e_C	scheduling error for sample conventional generator(s)	MWh	1 hour

5.3 Load Following Analysis Results

5.3.1 FORECAST AND SCHEDULING ERROR WITHOUT RENEWABLE GENERATORS

Load forecasts are prepared by CaISO and provide the best estimate of the upcoming system load conditions. Figure 5.3 presents a graphical comparison of the hour ahead forecast load and the actual load for several September days.

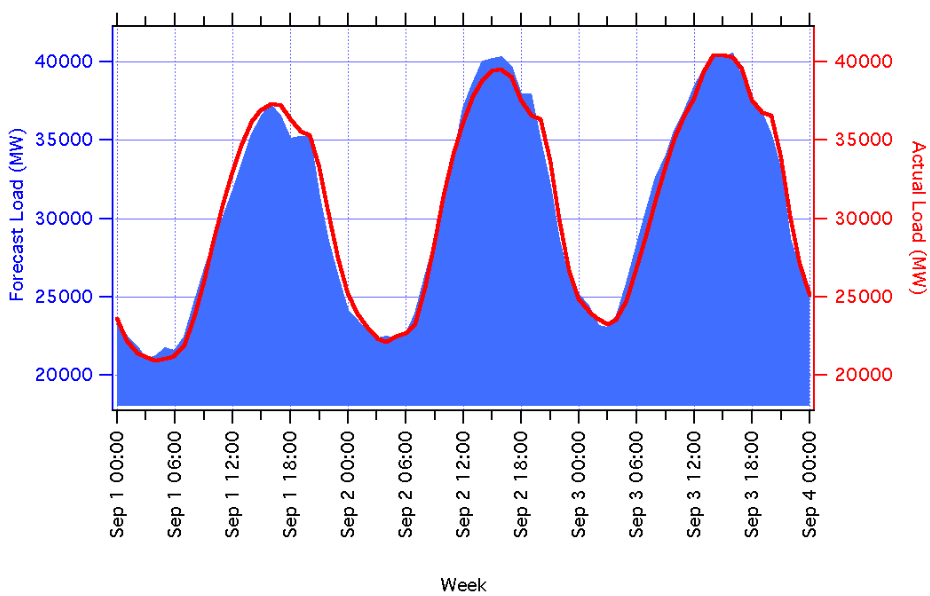

Figure 5.3 Forecast and Actual Load for Several September Days

The scheduled load is created by the scheduling coordinators based on forecast information available from CaISO and conditions in the energy markets. The hour ahead schedule as compared to the actual load is presented in Figure 5.4 for several example days in September. During peak hours the scheduled load is typically well below the forecast load and the scheduling coordinators rely upon the hour ahead market to provide the difference. The magnitude of the scheduling error provides a measure of the depth of the BEEP stack and indicates that the hour ahead market can be relied upon for large amounts of power to meet short term needs.

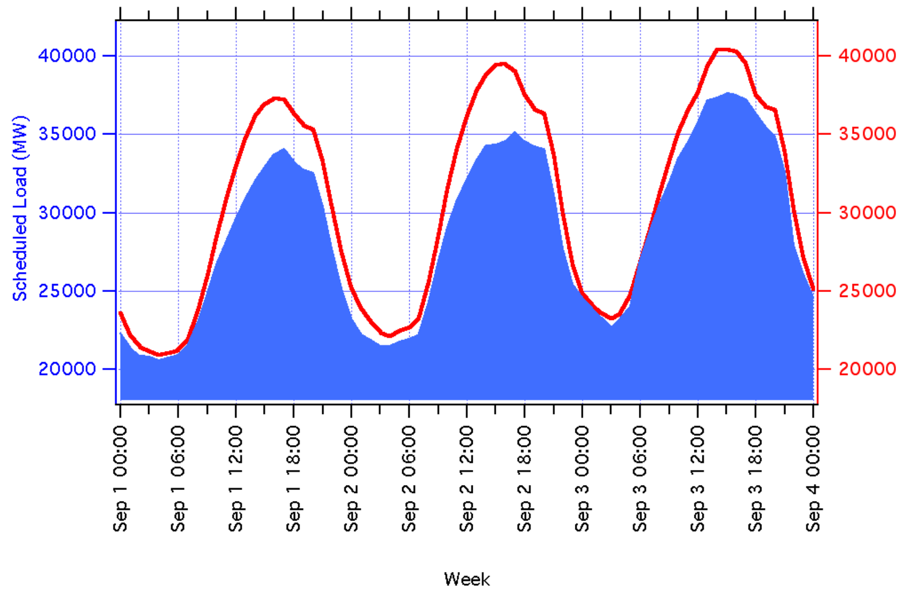

Figure 5.4 Scheduled and Actual Load for Several September Days

The difference between the scheduled load and the forecast load is called the scheduling bias. The scheduling bias is typically negative (scheduled generation is less than forecast load) and reaches the largest negative values during peak summer hours. For the example year the scheduled generation was as much as 5688 MW less than forecast load (Figures 5.5 through 5.7).

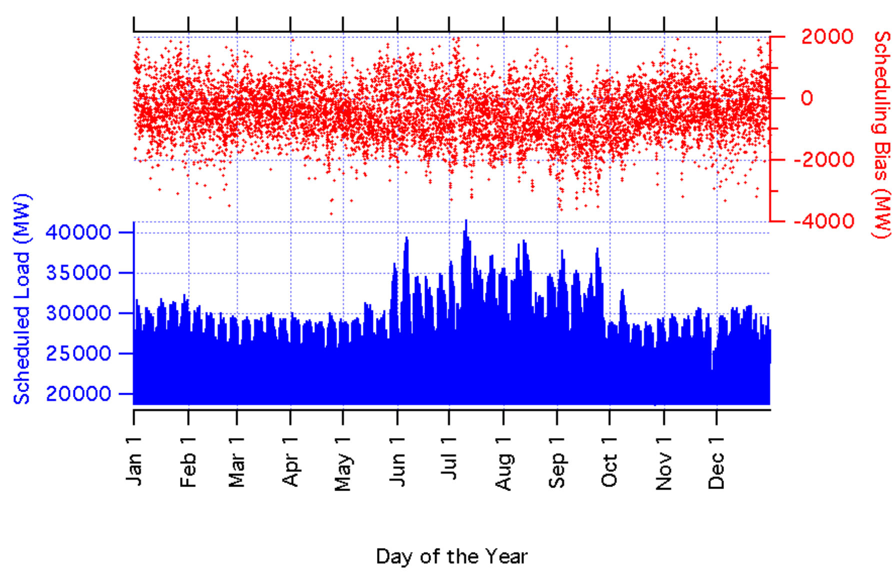

Figure 5.5 Scheduled Load and Scheduling Bias

The scheduled load provided by the scheduling coordinators is often thousands of megawatts less than the forecast load created by CaISO. The large negative bias of the hour ahead schedules provides an indication of the amount of the generation assets available in the supplemental energy market. The data indicates that the scheduling coordinators are comfortable with the depth of the BEEP stack; they can call up at least 6000 MW of generation from the market whenever it might be needed. For our initial analysis the scheduling bias was used as a proxy for estimating the depth of the BEEP stack. It was used for comparison purposes in determining the significance of renewable impacts on the system error.

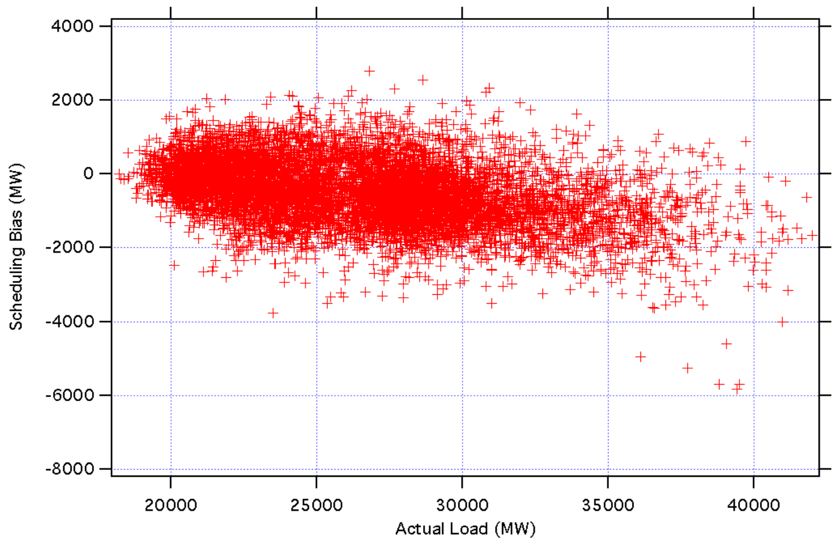

Figure 5.6 Load Versus Scheduling Bias

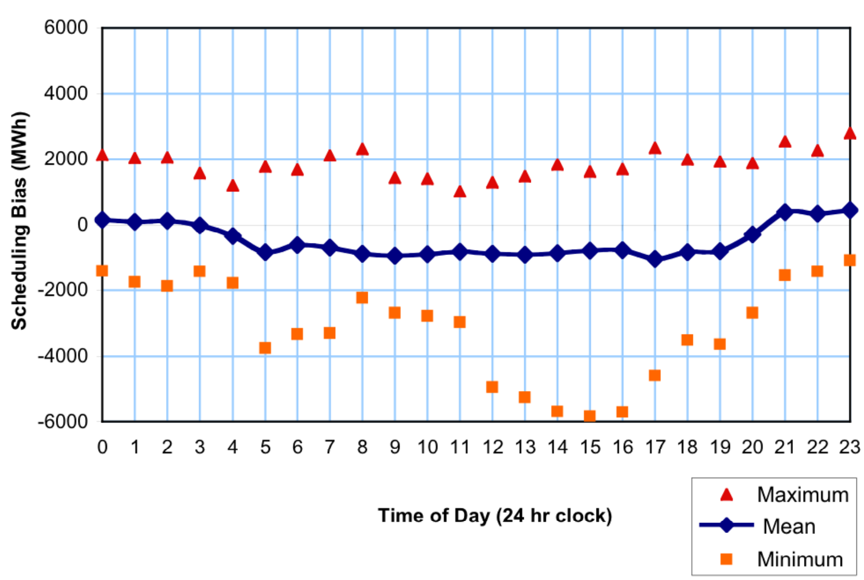

Figure 5.7 Average Scheduling Bias Versus Time of Day

The hourly energy requirements for the example year are compared against the forecasting error in Figure 5.8. The same information is shown for several example days in Figure 5.9. These graphs show the magnitude of the forecasting error without impacts associated with renewable generators and provide a benchmark for comparison.

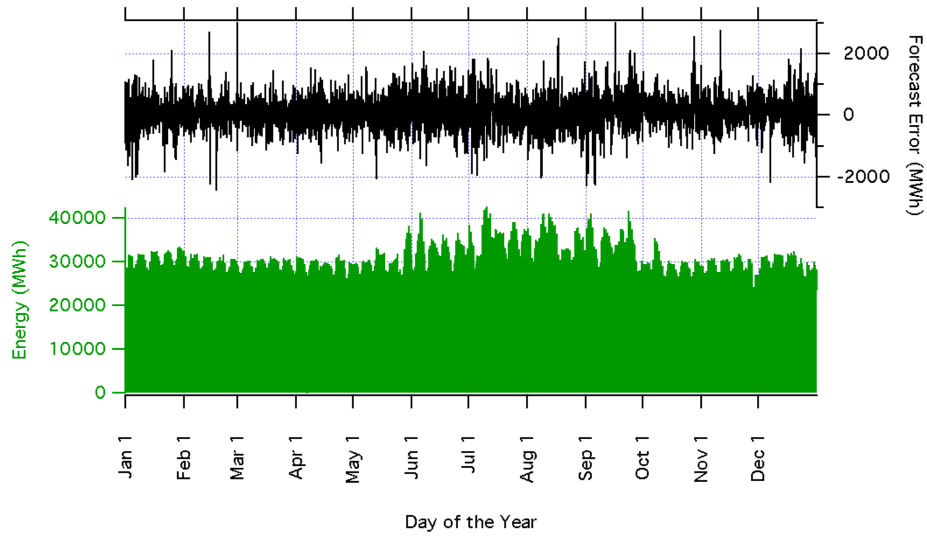

Figure 5.8 Hourly Energy Requirements and Forecasting Error for the Sample Year

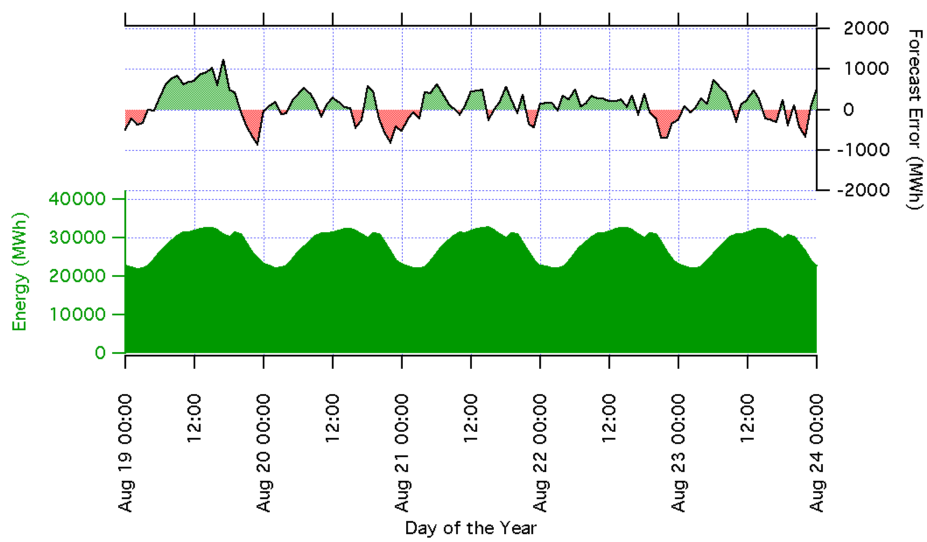

Figure 5.9 Energy Requirements and Forecasting Error for Several August Days

5.3.2 RESOURCE HOUR AHEAD SCHEDULES

The hour ahead schedules for each renewable generator of interest were developed using the simple persistence model described earlier. This model provides a schedule of renewable output for the hour ahead market and is a conservative (worst case) approach. Use of forecasting models will reduce scheduling error and reduce the significance of renewable impacts from those calculated here.

Using wind energy as an example, figures 5.10 through 5.12 show comparisons of actual and scheduled total wind generation at several different time scales.

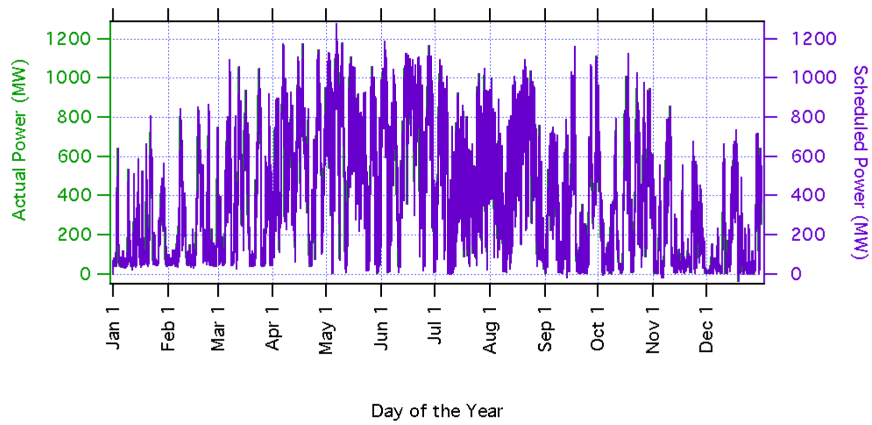

Figure 5.10 Actual and Scheduled Total Wind Generation for the Year

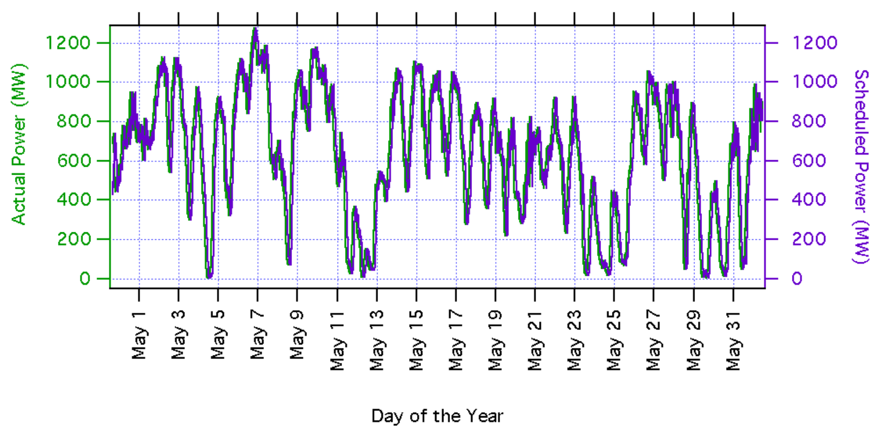

Figure 5.11 Actual and Scheduled Total Wind Generation in May

The simple persistence model works reasonably well for estimating output from intermittent renewable generators when viewed at a time scale of weeks to months. On the monthly scale, shown in Figure 5.11, the scheduled wind output tracks the actual generation quite well. When viewed on a time scale from hourly to daily the scheduling errors become more apparent, as shown in Figure 5.12. However, even on this scale there are periods where the scheduled and actual generation are nearly equal.

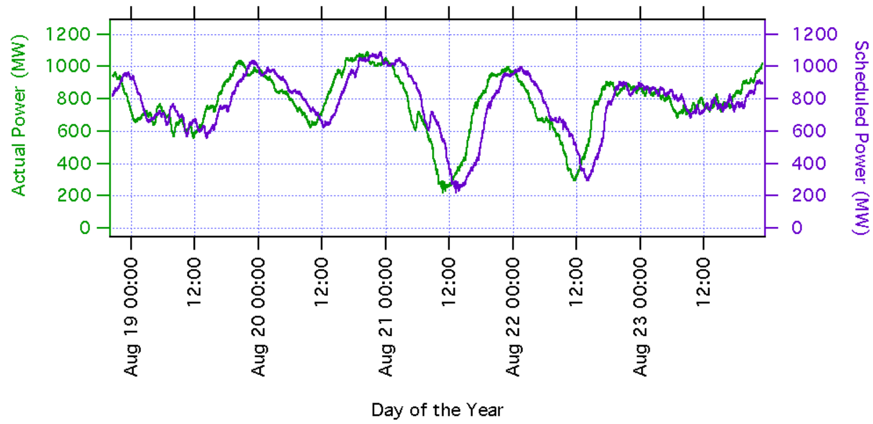

Figure 5.12 Actual and Scheduled Total Wind Generation for Several Days in August

5.3.3 RESOURCE SCHEDULING ERROR

The resource scheduling error for each renewable generator of interest was calculated as the difference between the scheduled and the actual output. Using wind energy as an example, Figures 5.13 through 5.14 show comparisons of total wind energy and scheduling error at several different time scales. The scheduling error represents the amount of energy which must be purchased from the hour ahead market

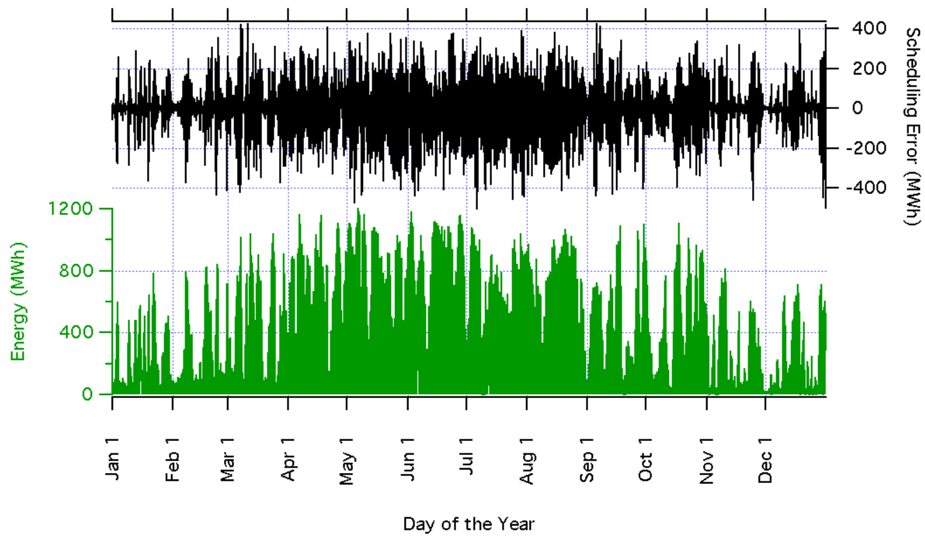

Figure 5.13 Total Wind Generation and Scheduling Error for the Sample Year

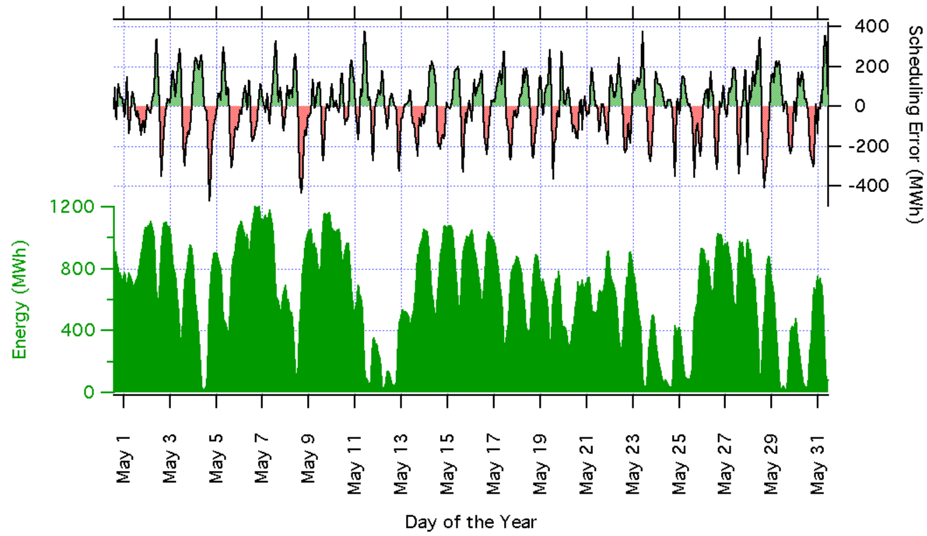

Figure 5.14 Total Wind Generation and Scheduling Error in May

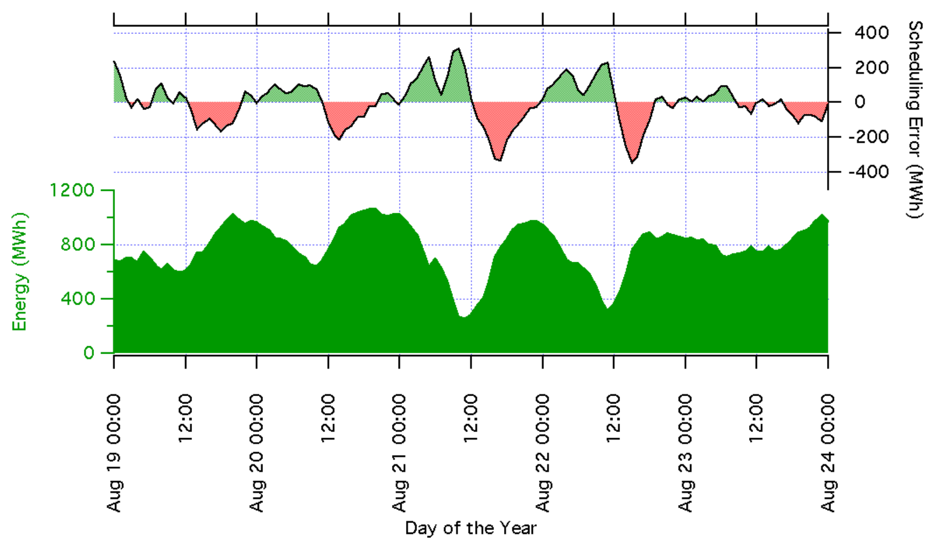

Figure 5.15 Total Wind Generation and Scheduling for Several Days in August

5.3.4 FORECASTING AND SCHEDULING ERROR INCLUDING RENEWABLE GENERATORS

The scheduling error for each renewable resource was combined with the system forecasting error for each hour of the sample year. The result of this combination showed the impact of renewable generation on forecasting error, which could then be compared against the benchmark case without renewable generation. Figures 5.16 through 5.18 provide comparisons of forecasting errors with and without wind generation at several different time scales.

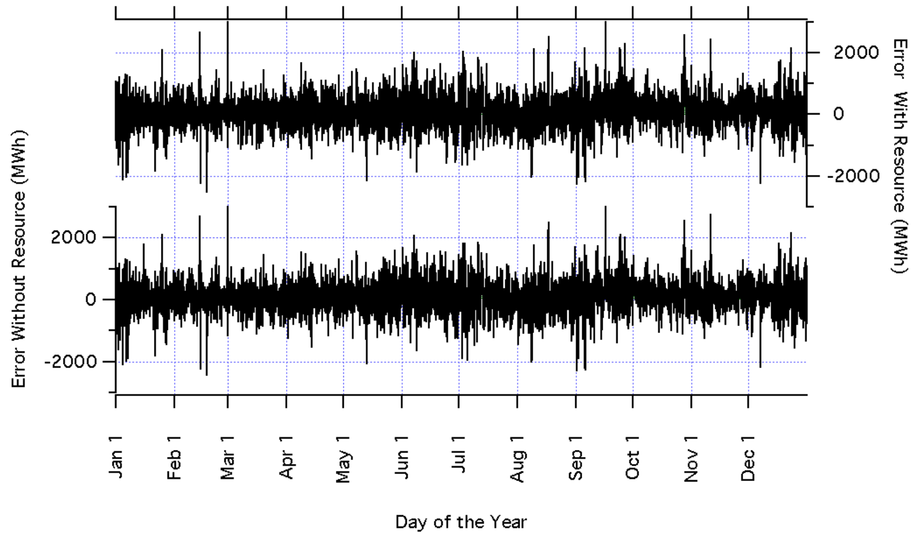

Figure 5.16 Forecasting Error With and Without Wind Generation for the Sample Year

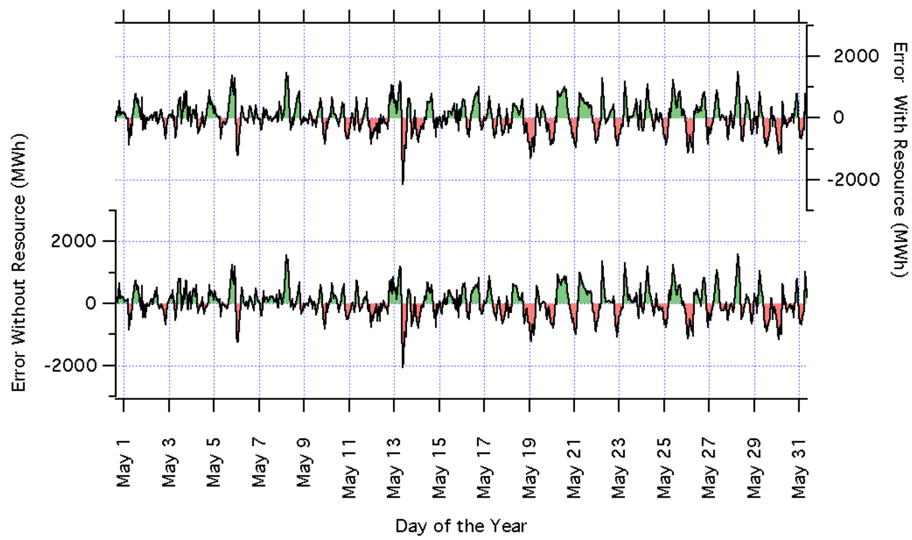

Figure 5.17 Forecasting Error With and Without Wind Generation in May

For the total wind generation shown in this example, there are few obvious differences in forecasting error that can be observed at any time scale. System forecasting error including the wind generation scheduling error is somewhat different than the benchmark case of forecasting error alone, but the changes are not dramatic. Figure 5.19 provides a graph showing the correlation of forecasting error with wind generation and forecasting error alone. Wind scheduling error has the largest impact when the overall forecasting error is small and has minimal impact at the extremes. It is important to remember that this was a worst-case analysis using a simplistic approach for developing the hour ahead schedule.

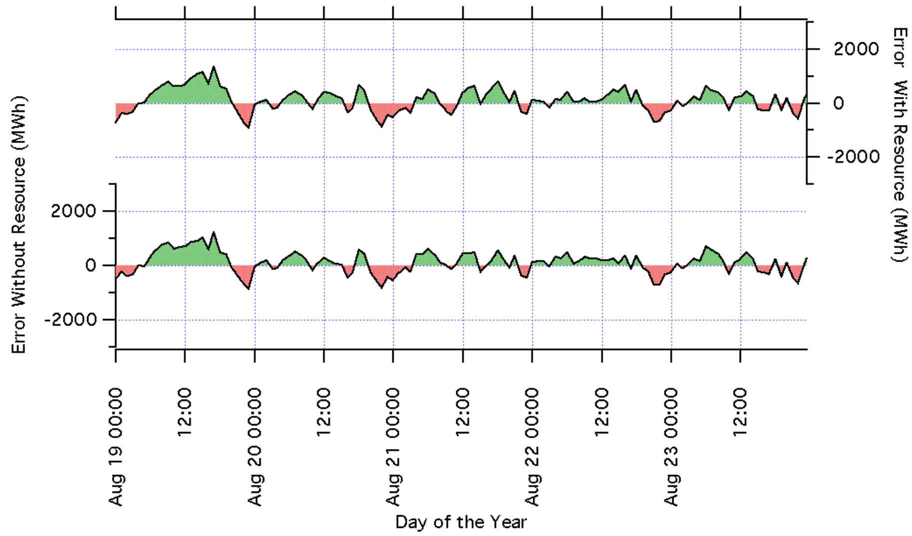

Figure 5.18 Forecasting Error With and Without Wind Generation for Several Days in August

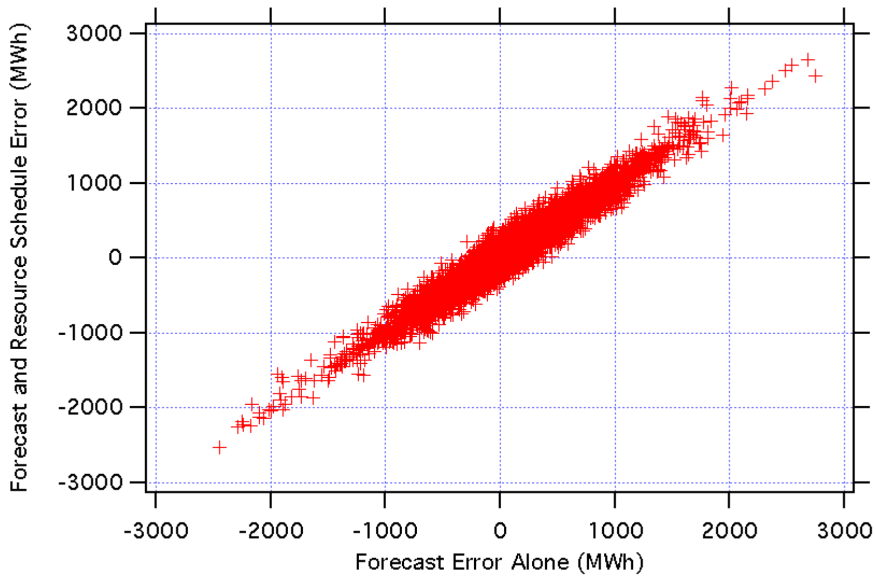

Figure 5.19 Correlation Between Forecasting Error Alone Forecasting Error With Wind Generation

5.3.5 LOAD FOLLOWING ANALYSIS RESULTS

The forecasting error including the scheduling error for each renewable resource of interest was calculated. We compared the average minimum and maximum forecasting error during peak hours (noon to 6 pm) as a means of evaluating the significance of the renewable generator impacts. Minimum forecasting error was unchanged or slightly improved for all renewable resources. This means that renewable scheduling errors tended to reduce the magnitude of incremental energy purchases during peak hours. Maximum forecasting error was unchanged or slightly increased for all renewable resources. This means that renewable scheduling errors tended to increase the magnitude of decremental energy purchases during peak hours.

Table 5.3 Impact of the Scheduling Error of Each Renewable Resource on the Forecast Error

RESOURCE	COMBINED FORECAST ERROR AND RENEWABLE SCHEDULING ERROR			
	Average Minimum		Average Maximum	
	MW	Compared to forecast error w/out renewables (%)	MW	Compared to forecast error w/out renewables (%)
Forecast error without renewables	-1909	100%	2220	100%
Biomass	-1897	99%	2218	100%
Geothermal	-1878	98%	2221	100%
Solar	-1870	98%	2220	100%
Wind (Altamont)	-1909	100%	2272	102%
Wind (San Gorgonio)	-1898	99%	2226	100%
Wind (Tehachapi)	-1884	99%	2281	103%
Wind (total)	-1870	98%	2377	107%
Scheduling bias	-5076	266%	1747	79%

Based on the results of this analysis, the impacts of renewable generators are small when compared against the bias introduced by the scheduling coordinators. As we discussed earlier, the scheduling bias provides an indication of the depth of the BEEP stack. Therefore impacts which are small relative to the scheduling bias were not considered to significantly change the stack size or composition. These results indicate that renewable resources have no significant impacts on the stack at current levels of market penetration.

5.4 Load Following Analysis Recommendations

This preliminary analysis shows that there is no significant impact of existing renewable generators in the load following time scale. These results are sufficiently robust so that little impact should be expected if reasonable amounts of additional renewable resources are added to the system. The calculated impacts are much less than the bias effects created by the scheduling coordinators. More detailed analyses are recommended to evaluate the effects of increased renewable penetration and the impacts on contingency reserves.

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APPENDIX A: CONTROL PERFORMANCE STANDARDS[1]

The electrical power system operated by the *California Independent System Operator* (CaISO) is called its *control-area*. Power plants, or *generators*, located throughout the state are managed in real-time to meet the demands, or *loads,* of electricity customers. Because electricity is a real-time product in which loads and generation fluctuate and cannot be perfectly predicted, control-area operators, or *dispatchers*, must constantly adjust generation to meet load. CaISO manages electrical *energy*, generating *capacity*, and other *ancillary services* that are used to maintain control and reliability of the California utility grid.

The CaISO must manage its generators to compensate for the real-time variations between actual generation and actual load in the electric system. The *North American Electric Reliability Council* (NERC) recognizes the *area control error* (ACE) as a primary metric used to assess the performance of the control operator. Each control area seeks to minimize its effects on the neighboring control areas to which it maintains an *interconnection*. Errors incurred because of generation, load or schedule variations or because of jointly owned units, contracts for regulation service, or the use of dynamic schedules must be kept within the control area and not passed to the interconnection. The equation for ACE is:

$$ACE = (NI_A - NI_S) - 10ß\,(F_A - F_S) - I_{ME} \qquad [A.1]$$

In this equation, NI_A accounts for all actual meter points that define the boundary of the control area and is the algebraic sum of flows on all tie lines. Likewise, NI_S accounts for all scheduled tie flows of the control area. The combination of the two (NI_A - NI_S) represents the ACE associated with meeting schedules and if used by itself for control would be referred to as flat tie line regulation.

The second part of the equation, 10ß (F_A - F_S), is a function of frequency. The 10ß represents a control area's frequency bias (ß's sign is negative) where ß is the actual frequency bias setting (MW/0.1 Hz) used by the control area and 10 converts the frequency setting to MW/Hz. F_A is the actual frequency and F_S is the scheduled frequency. F_S is normally 60 Hz but may be offset to effect manual time error corrections. I_{ME} is the meter error recognized as being the difference between the integrated hourly average of the net tie line instantaneous interchange MW (NI_A) and the hourly net interchange demand measurement (MWh). This term should normally be very small or zero.

The North American Electric Reliability Council *Control Performance Standards* (CPS) 1 and 2 set statistical limits on the allowable differences between one-minute averages of the control area's difference between aggregated generation and interchange schedules relative to load (i.e., ACE). CPS1 measures the relationship between the control area's ACE and its interconnection frequency on a one-minute average basis. CPS1 values are recorded every minute, but the metric is evaluated and reported annually. NERC sets minimum CPS1 requirements that each control area must exceed each year. CPS2 is a monthly performance standard that sets control-area-specific limits on the maximum average ACE for every 10-minute period.

Neither CPS1 nor CPS2 require that the ISO maintain a zero value for ACE. Small imbalances are generally permissible, as are occasional large imbalances. Both CPS1 and CPS2 are statistical measures of imbalance, the first a yearly measure and the second a monthly measure. Also both CPS standards measure the aggregate performance of the control area, not the behavior of individual loads or generators. Control areas are permitted to exceed the CPS2 limit no more that 10% of the

[1] North American Electric Reliability Council. *NERC Operating Manual.* Princeton, NJ, November 2002.

time. This means that a control area can average no more than 14.4 CPS2 violations per day during any month.

APPENDIX B: REGULATION ALLOCATION METHODOLOGY

This regulation impact allocation method[1] was developed by Oak Ridge National Laboratory to deal with nonconforming loads. It works equally well with uncontrolled generators that are not using either AGC or ADS. The methodology meets several desirable objectives:

- Recognize positive and negative correlations
- Be independent of subaggregations
- Be independent of order in which generators or loads are added to system
- Allow disaggregation of as many or few components as desired

The methodology has been used by a number of analysts to analyze the regulation impacts of loads, conventional generators that are not on AGC or ADS, and non-dispatchable renewable generators.

We can think of regulation as a vector and not just a magnitude. For example, start with load *A*. It might be a single house or an entire control area with a regulation impact of 8. Consider another load *B* with a regulation impact of 6 that we want to combine with *A*. If loads *A* and *B* are perfectly correlated positively, they add linearly, as shown in the top of Figure B.1. If the two loads are perfectly correlated negatively, their regulation impacts would add as shown in the middle of Figure B.1. Typically, loads are completely uncorrelated and the regulation requirement for the total is the square root of the sum of the squares, or 10 in this case (bottom of Figure B.1).

Multiple uncorrelated loads are always at 90 degrees to every other load. They are also at 90 degrees to the sum of all the other loads. This characteristic requires adding another dimension each time another load is added, which is difficult to visualize beyond three loads. Fortunately, the math is not any more complex. The fact that each new uncorrelated load is at 90 degrees to every other load and to the total of all the other loads is quite useful. The analysis of any number of multiple loads can always be broken down into a two-element problem, the single load and the rest of the system.

Return to the two-load example but consider the more general case where loads *A* and B are neither perfectly correlated nor perfectly uncorrelated. We may know the magnitude of *A* and the magnitude of *B*, but we do not know the magnitude of the total without measuring it directly (i.e., we do not know the *direction* of each vector). We can, however, measure the total regulation requirement and use this vector method to *allocate* the total requirement among the individual contributors.

[1] Kirby, B. and E. Hirst, "Customer Specific Metrics for the Regulation and Load-Following Ancillary Services", ORNL/CON-474, Oak Ridge National Laboratory, Oak Ridge, TN, January 2000.

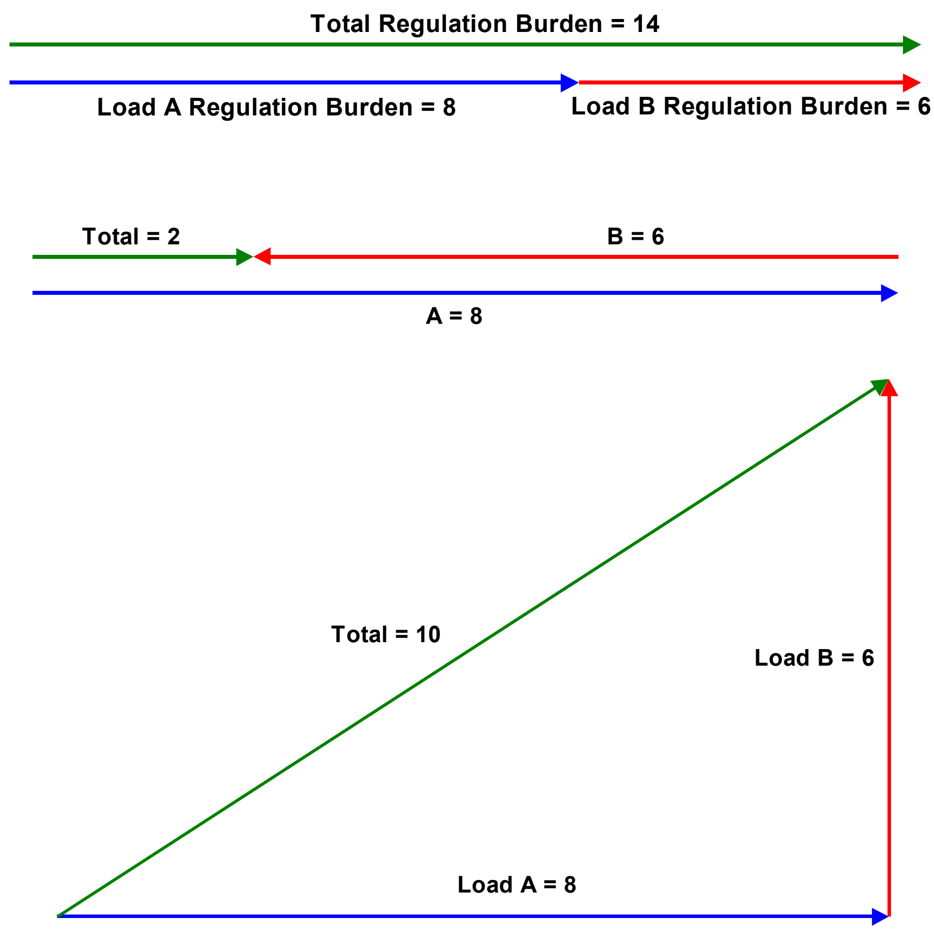


Figure B.1 The relationships among the regulation components (A and B) and the total if A and B are positively correlated (top), negatively correlated (middle), or uncorrelated (bottom).

We know the total regulation requirement because we meter it directly as the aggregated regulation requirement of the control area. We can know the regulation requirement of any load by metering it also. We can know the regulation requirement of the entire system less the single load we are interested in by calculating the difference between the system load and the single load at every time step, separating regulation from load following, and taking the standard deviation of the difference signal. Knowing the magnitudes of the three regulation requirements, we can draw a vector diagram showing how they relate to each other (Figure B.2).

How much of the total regulation requirement is the responsibility of load *A*? We can calculate the amount of A that is aligned with the total and the amount of *B* that is aligned with the total. We can do this geometrically (as shown below) or with a correlation analysis.

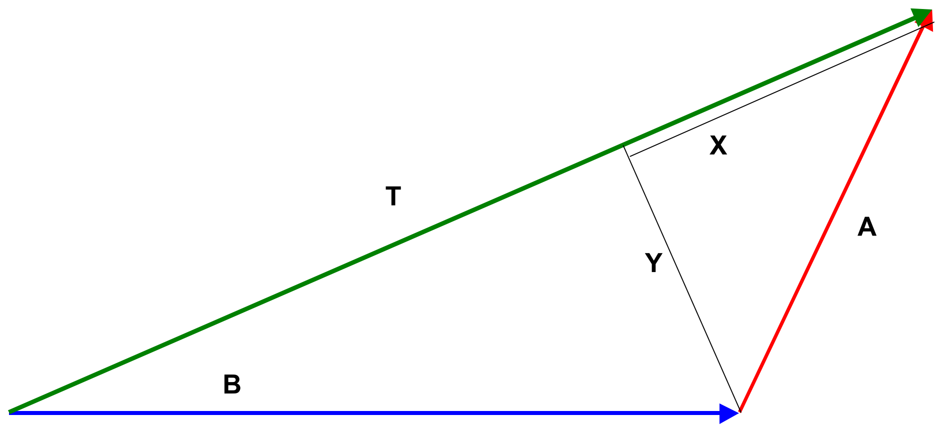


Figure B.2 The relationship among the regulation impacts of loads A and B and the total (T) when A and B are neither perfectly correlated nor perfectly uncorrelated.

Y is perpendicular to the total regulation T (uncorrelated). X is aligned with T (correlated). A's contribution to T is X. Knowing A, B, and T, we can calculate X. (We could also calculate Y, but there is no need to do so.) We can write two equations relating the lengths of the various elements:

$$A^2 = X^2 + Y^2 \tag{B.1}$$

$$B^2 = (T - X)^2 + Y^2 \tag{B.2}$$

Subtract Equation B.2 from Equation B.1 to get,

$$A^2 - B^2 = X^2 - (T - X)^2 + Y^2 - Y^2$$

$$A^2 - B^2 = X^2 - (T^2 - TX - TX + X^2) = 2TX - T^2$$

Solving for X (load A's contribution to the total T) yields,

$$X = (A^2 - B^2 + T^2)/2T \tag{B.3}$$

We can decompose a collection of any number of loads into a two-load problem consisting of the load we are interested in and the rest of the system without that load (Figure B.3). We can solve Equation B.3 for as many individual loads as we wish. Variable T remains the total regulation requirement, variable A becomes each individual load's regulation requirement, and variable B becomes the regulation requirement of the total system *less* the specific load of interest.

This allocation method works well with any combination of individually metered loads and load profiling for the remaining loads. The load profiling can be as simple as making the usual assumption that the other loads' regulation requirements are proportional to their energy requirements. Or measurements of a sample set can be taken to determine the magnitude of their regulation impacts. This vector-allocation method is used to determine the regulation impact of each of the metered loads. The residual regulation impact is then allocated among the remaining loads, assuming they are perfectly uncorrelated.

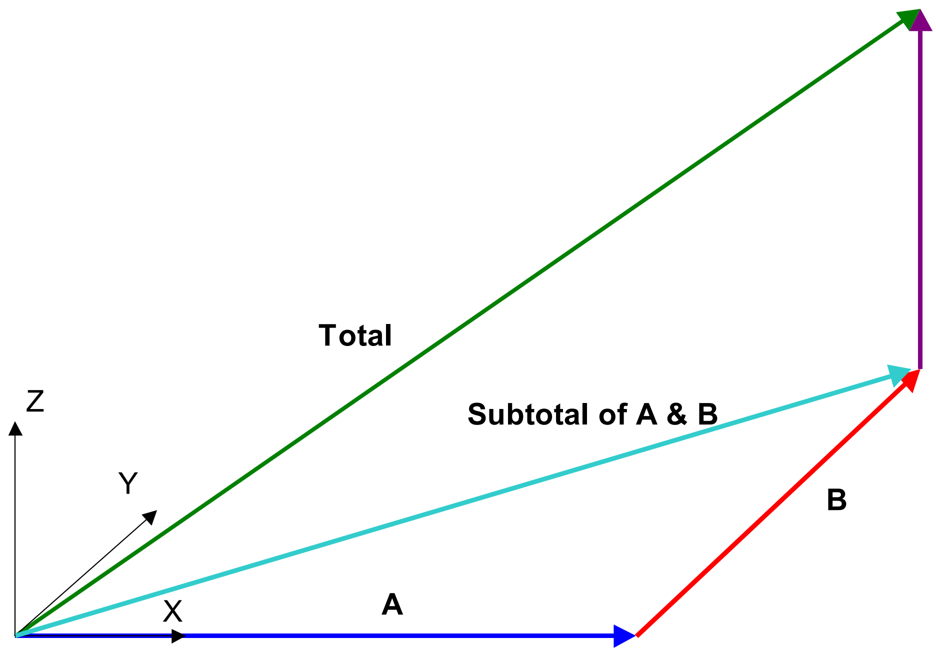


Figure B.3 Application of Vector-Allocation Method to the Case with More Than Two Loads.

APPENDIX C: PUBLIC COMMENTS

Comments submitted to rpsintegration-Q@cwec.ucdavis.edu and responses are presented in this section. Comments are presented in the order in which they were received.

Before addressing any specific comments, it is worthwhile to restate the scope and some of the limitations of the Phase I study. The primary purpose of the Phase I study was to test the analysis methodologies and identify issues in their implementation and application by analyzing one year of California electrical system, generation, and market data. By using a full year of actual data, a secondary goal of Phase I was also accomplished — determining interim values for immediate use in RPS bid selection. The Phase I results have some limitations, but as interim findings, will be superceded by more thorough analyses in the coming months.

The limitations of the Phase I findings can be grossly categorized as either inherent to the Phase I analysis parameters or an issue with input data. As defined in the overall study plan, the benefits of specific generation technologies and siting and the effects of increased penetration and fuel supply will be investigated in Phases II and III. Comments to this report pertaining to technologies, siting, penetration, and fuel are being considered in the remaining phases of this study. Additional comments regarding these issues can be voiced at the study's discussion mailing list at rpsintegration-workinggroup@cwec.ucdavis.edu.

Phase I was also defined as a one year analysis. Subsequent phases will expand to other years. This will be facilitated by improved procedures for obtaining input data, as discussed below. Analysis of multiple years will mitigate the effects of various anomalous electrical system, climatic, or market events which seem to crop up each year. The final methodology for this study will likely employ a periodic rolling analysis of a number of recent years to stay current.

The results of the analyses are also necessarily limited by its input data. The Methods Group has had the generous cooperation and extensive efforts of CaISO in obtaining the needed data, but, as discovered in the course of executing Phase I, acquiring the data remains a nontrivial task because of the high sampling frequency required, the proprietary nature of such data, and the logistics of mining CaISO's vast data warehousing systems. Although the Methods Group has actively lobbied for non-aggregated data since the preliminary stages of this study, aggregation was necessary to satisfy confidentiality requirements. Note that descriptions of the aggregates have been added to Sections 2.1.4 through 2.1.7. In remaining sensitive to the confidential nature of the data, the descriptions are limited. However, non-aggregated data is essential to the completion of the study. Solutions for the legal issues have been devised and with the experience garnered over Phase I, the processes for finding and retrieving the right data from CaISO's PI system are now significantly more efficient. Also, the Methods Group welcomes the direct contribution of generation data by IOUs or plant operators or owners. To discuss supplying data to this study, contact the Methods Group directly at rpsintegration-methodsgroup@cwec.ucdavis.edu.

Finally, the Methods Group would like to sincerely thank the commenting parties and all those who have participated in the workshops and e-mail lists. Although Phase I is now formally complete, please do not hesitate to provide feedback on it or the remainder of the study through the study discussion mailing list at rpsintegration-workinggroup@cwec.ucdavis.edu.

C.1 Comments from Solargenix, Received 24 October 2003

Solargenix Energy, LLC Comments on
California Renewables Portfolio Standard
Renewable Generation Integration Cost Analysis
Dated: October 9, 2003

Phase 1: One Year Analysis of Existing Resources
Results and Recommendations
Final Report

Introduction

Solargenix is pleased to review the subject report and acknowledges the time and effort expended by its principle contributing parties:

- Oak Ridge National Laboratory;
- National Renewable Energy Laboratory;
- California ISO; and,
- California Wind Energy Collaborative

Based on what was presented in the report, the methodology used appears to be appropriate and fair to the renewable energy resources evaluated; however, the report was not sufficiently complete to fully understand the authors' methods. The report, as presented, precludes a thorough analysis on the manner actually used to determine the results and conclusions. Consequently, the comments by Solargenix concentrate on the data, inputs and assumptions used to arrive at the reports findings. In particular, Solargenix finds the 56.6% (Relative Capacity Credit listed on page xi of the Executive Summary) to be inconsistent with experience realized at the existing SEGS solar thermal (with gas assist) located near the Kraemer Junction area in Southern California. The purpose of these comments is to suggest better understandings of solar thermal technology with gas assist (and/or thermal storage) and operational scenarios that may result in the recognition of higher capacity values.

Discussion of Specific Comments

Solargenix has prepared comments to specific items in the report and also has attached certain operating statistics to explain our position that the Relative Capacity Credit attributed to a gas assisted solar thermal power plants is inordinately low. One of the most valuable attributes of solar thermal with gas assist is its ability to reliably supply load coincident generation; the capacity value of solar thermal with gas assist and/or equivalent storage should not be compared to other types of renewables since it is one of the few, if not the only commercially available, renewable technology that supplies on peak, dispatchable premium power to the grid. In general, the report's methodology should include generator data that compares the coincident load that the generation serves. This is particular true for solar generation with gas assist or thermal storage that can match the needs of the grid during diurnal operation.

Solargenix is unsure that a true coincident load analysis can be performed (as the methodology indicates) that uses only the top 500 hours (see page 26, figure 3.1). The top hours served do not necessarily always correspond to the most critical periods served by the IOU due to maintenance, forced outage rates of units and contract obligations.

In addition, the report apparently separates the solar portion from the gas assist generation and only the solar produced electricity is evaluated for performance. In other words, the gas assisted solar plant is evaluated as if there is no gas assist and the plant output would therefore be subject to the vagaries of cloud transients and cloudy/hazy days. <u>If so, this criteria used in the report would be in error</u>. The gas assisted solar thermal power plant must be evaluated as a whole since the product produced as a whole is what serves the grid. The fact that it has a solar assist should not be given negative consideration in the report as the contract with Edison (and any future PPA) is based on the overall product delivered to the grid. Gas assist and/or equivalent storage is a distinct advantage associated with solar thermal and this advantage should not be discounted in the analysis.

Solargenix has the following specific comments on the report:

1. <u>Page xi, last paragraph</u>
   The report states…*"Given the diurnal correlation between solar power and load, one would also expect a mid-range or high value range [Relative Capacity Credit], depending on how often the solar generates less than full output during peak periods."* This statement strongly suggests the report is evaluating a pure solar plant without the benefit of gas assist. Pure solar thermal plants that use turbines for power generation cannot be reliably or economically operated since there must be compensation, e.g. gas assist or thermal storage, for cloud cover and other thermal transients. Solargenix is proposing gas assist solar thermal generation (or thermal storage) to ensure that capacity is provided during cloud cover or periods of need.

2. <u>Page 2, first paragraph</u>
   The report states... *"A generator's ability to deliver power when needed provides capacity value to the system that is separate and distinct from the energy it generates."* A gas assisted solar thermal plant fulfills the need of the grid to be serviced by capacity when called upon. This is what distinguishes solar thermal with gas assist from an intermittent resource such as wind. With gas assist or thermal storage, the solar plant is delivering "capacity" as well as "energy".

3. <u>Page 6, under section 2.1.2 "Data Collection"</u>
   The exact data collected for the solar thermal analysis is not listed. While obviously raw data would be too cumbersome to compile for this summary report, a sample of the data used would be most helpful in determining exactly what was

used in the analysis. In addition, the report states that it used aggregated solar plants; it would be beneficial to the reader to list those plants whose operating statistics were used to compile the report.

4. Page 11, Figure 2.9
The charts presented in the report shows significant fall off of solar thermal generation during specific August and September days. This fall-off would result in serious degradation in the capacity value of solar thermal generation since it would appear that the SEGS solar thermal generation stations are not meeting Edison's needs. Edison defines their on-peak, mid-peak and off-peak energy periods as follows:

SEASONAL AND TOD PERIOD DEFINITIONS

TOD Period	**Summer Period June 1 - September 30**	**Winter Period October 1 - May 31**	
On-Peak	Noon - 6:00 p.m.	n/a	Weekdays except Holidays
Mid-Peak	8:00 a.m. - Noon	8:00 a.m. - 9:00 p.m.	Weekdays except Holidays
	6:00 p.m. - 11:00 p.m.		Weekdays except Holidays
Off-Peak	11:00 p.m. - 8:00 a.m.	6:00 a.m. - 8:00 a.m.	Weekdays except Holidays
		9:00 p.m. - Midnight	Weekdays except Holidays
	Midnight - Midnight	6:00 a.m. - Midnight	Weekends & Holidays
Super-Off-Peak	n/a	Midnight - 6:00 a.m.	Weekdays, Weekends & Holidays

Holidays: New Year's Day, Presidents' Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day and Christmas Day. When any holiday listed above falls on Sunday, the following Monday will be recognized as an Off-peak period. No change will be made for holidays falling on Saturday.

Accordingly, it can be reasonably expected that the solar plants' on-peak capacity factor would show a significant drop consistent with the results presented on Figure 2.9. However, this is not the case. For comparison, Solargenix has attached the SEGS "Annual Production Summary" (Appendix A) for years 1997-2001. As noted, the on-peak capacity factor values for on-peak load exceed 100% of nameplate capacity for all years for all units. Further analysis for prior years is shown in Figure 10 (Appendix B) that lists on-peak capacity factors for the 1989 –1998 time period. As noted, the SEGS units never failed to meet the contract "name plate" capacity value in this 10 year period. Consequently, the capacity drop off as shown in Figure 2.9 is inconsistent with the SEGS plants recorded on-peak capacity factors.

5. Page 23, Section 3.1 definition of LOLE and ELCC
The authors define the Effective Load Carrying Capability when C_i satisfies the following equation:

$$\sum_{i=1}^{N} P(C_i < L_i) = \sum_{i=1}^{N} P[(C_i + g_i) < (L_i + C_i)]$$

where: C_i is defined as the available capacity in a given hour;
L_i is defined as the load in a given hour; and,

g_i is defined as the incremental generation.

During the workshop on September 12th, comments were made regarding the impact of the ELCC when N is set at 8760. The consensus was that while there would be an impact on the ELCC value, this impact would be minimal since the loss of load probability cannot be expected to be significant during the off-peak or mid-peak hours. However, as previously mentioned, the on-peak period is not always coincident with the inability to meet load. Since the solar unit is obviously "off" during certain non-peak times when generation sufficiency may be at risk, the use of N=8760 could significantly reduce the ELCC when applied to solar evaluation. It is more accurate to measure the uncertainty of meeting coincident load within the confines of a solar thermal plant (with gas assist) operating in the diurnal operational mode only. The gas assist is to warrant output and performance when the unit is available but clouds preclude maximum output. In this manner, the total annual availability of the plant would be significantly reduced but the unit could have a higher ELCC.

A counter argument to the above is that if the solar unit is not available at night or mid-peaks to meet those times when generation sufficiency may be at risk, then the ELCC should be reduced (as is reflected in the report's evaluation method). However, with gas assist, the solar unit is available for night operation or periods of need. Due to the poor heat rate, the unit would almost never be operated at night; however, it could be. Consequently, the discretionary non-use of the solar asset should not be construed as a non-discretionary inability to use the asset. The voluntary non-use of the asset should not be used in the ELCC calculations.

6. Page 27, Figure 3.2.3 (Baseline FOR)
   The chart shows a forced outage rate for gas turbines at 10% in order to produce a normalized ELCC of 100%. This FOR appears high and Solargenix would recommend a more realistic value consistent with FOR published by EEI or NERC.

7. Page 30, first paragraph
   The text indicates that the solar is "intermittent" and subject to reduced output during peak times due to cloud cover. Referencing Appendices A&B, this is clearly not the case due to the back-up capability of the gas boiler. Accordingly, Solargenix does not believe that this is representative of a solar thermal plant with gas assist. Also, in Appendix C, the availability of the solar field is illustrated in Figure 4 (Solar Collection Assembly Availability). This figure shows that for a ten year period (1988-1998), the availability of the SEGS solar fields is rarely below 97%; later periods show even higher availability. Accordingly, these three appendices show that, with gas assist or thermal storage, the solar plants have demonstrated higher reliability to perform when called upon than the proxy gas turbine plant.

<u>Page 31, Figure 3.8</u>
The manner of calculating the standard deviation is unclear and how the standard deviation relates to equation 3.3 is not made clear to the reader. It is also unclear whether the same treatment and evaluation method was given the wind analysis. A chart comparable to figure 3.8 should be prepared for wind and the methodology for establishing the standard deviation at it relates to the ELCC should be discussed.

General Comments
The aggregation of data simplifies analysis but protects individual plants and their performance records from being identified. Consequently, the analysis fails to recognize several important factors. For example, the SEGS plants have contracts with SCE to provide power according to SCE peak needs and not California wide system peaks. These plants should be judged by their actual performance in the market in which they participate (local market) and not an aggregated California wide market. As noted in Appendix A, the SEGS plans served the local market quite well with capacity factors during peak hours always exceeding 100%! In addition, load aggregation assumes infinite transmission capacity within the state of California. For example, in evaluating wind it is assumed that the energy can be transported without limits and without constraints. It is possible that wind power within a region may have higher or lower correlation with regional loads than with aggregated state loads. This manner would tend to make the wind values "optimistic" rather than "conservative" (as stated in the text) since wind is scattered through out the state while the solar plants are fed into a common substation.

Final Comments

The ultimate judge of the renewable generator's capacity and energy value is the purchaser and operator of the plant. In the SEGS case, this is SCE. Edison has stated in its evaluation of the report that…"*with respect to ELCC, [Edison] noted that the ELCC for solar was 39% of nameplate and those for geothermal and biomass were much larger. Frankly, this result surprises us unless the solar data you used were based on a pure solar project (e.g., PV) and not a gas-assisted solar project. If it were supposed to be reflective of the latter (as I think it would need to be), it fails a fundamental smell test. SCE's solar thermal units have over the past 10 years consistently realized close to 100% of their maximum capacity bonus payments.* This comment from the purchaser who is the ultimate evaluator of contract performance is a strong argument for a re-evaluation of the 56.6% ELCC value given to solar thermal.

Conclusions and recommendations

- The report should not consider only "sun generated" portion of a solar thermal power plant. Solar thermal power plants will always have, to a certain extent, some sort of storage or gas assist to ensure continuity of operation. This is required not only because of technical cycling consideration of large equipment associated with solar thermal generation but also for the obvious economic advantages of providing firm, on –peak dispatchable energy to the IOU. In some cases, gas assist is not used for various reasons, and thermal storage is then used to provide the necessary thermal continuity of operation. The plant, whether with thermal storage or gas assist, is also sold as a package to provide firm capacity and energy at specified times. The dis-aggregation of the thermal storage/gas assist from the solar generated generation portion defeats the primary advantage of this technology over other forms of renewable energy. Solargenix recommends that the solar thermal generation capability and equivalent load carrying capacity (ELCC) value should be based on the aggregated operating criteria of the solar thermal plant using either gas assist or thermal storage to ensure capacity delivery.

- Data from the existing SEGS plants should be used, within the context of the Edison contract, should be used to determine ELCC values.

- The ability to meet loads should be based on local markets and not an aggregated state load that may be subject to transmission constraints.

- Careful consideration should be paid to how coincident loads are met through renewable generation and not rely just on the top 500 hours.

Respectfully Submitted,

Mark Skowronski for
Solargenix

Appendix "A"

1997 ANNUAL PRODUCTION SUMMARY

Performance	III	IV	V	VI	VII	Total
Gross Electrical Prod						
Gross Solar - MWh	64,677	64,503	75,936	70,019	69,186	344,321
Gross Boiler - MWh	29,464	30,768	37,486	31,473	32,895	162,086
Gross Total - MWh	**94,141**	**95,271**	**113,422**	**101,492**	**102,081**	**506,407**
Net Elec Sold - A Chan						
On-Pk - MWh	15,461	15,456	16,883	16,511	16,437	80,749
Mid-Pk - MWh	47,586	47,489	64,387	54,205	54,904	268,572
Off-Pk - MWh	22,906	23,242	20,816	19,234	18,493	104,692
Super Off - MWh	0	0	0	0	0	0
Total - MWh	**85,953**	**86,188**	**102,086**	**89,951**	**89,834**	**454,012**
Net Purch - B Chan						
On-Pk - MWh	5	6	0	0	6	17
Mid-Pk - MWh	432	434	285	487	412	2,050
Off-Pk - MWh	1,158	1,160	1,336	1,570	1,384	6,608
Super Off-Pk - MWh	567	596	616	740	647	3,166
Total - MWh	**2,162**	**2,197**	**2,238**	**2,796**	**2,449**	**11,841**
Station Load						
Station Internal - MWh	8,188	9,083	11,336	11,541	12,247	52,395
Station Ext (B Ch) - MWh	2,162	2,197	2,238	2,796	2,449	11,841
Station Total - MWh	**10,349**	**11,280**	**13,573**	**14,337**	**14,696**	**64,235**
Station Internal - % of Gross	8.7	9.5	10.0	11.4	12.0	10.3
SCE Capacity Factor						
On-Pk - %	101.1	101.0	110.3	107.9	107.4	105.6
Mid-Pk - %	55.0	54.7	72.8	65.6	63.6	62.3
Off-Pk - %	20.3	20.5	18.1	17.3	16.5	18.5
Natural Gas Use						
Boiler - KSCF	374,242	387,766	462,104	338,003	353,404	1,915,519
Heater - KSCF	27,336	20,984	22,200	2,813	1,592	74,925
Total - KSCF	**401,578**	**408,750**	**484,304**	**340,816**	**354,996**	**1,990,444**
FERC Calc (LHV)						
Solar Energy Input - MMBtu	1,099,928	1,119,575	1,325,869	933,529	971,999	5,450,899
Gas Energy Input - MMBtu	366,149	372,687	441,664	310,981	323,739	1,815,220
FERC Ratio	**24.97**	**24.97**	**24.99**	**24.99**	**24.98**	**24.98**
FERC Excluded Gas - KSCF	0	0	0	0	0	0

1998 ANNUAL PRODUCTION SUMMARY

Performance	III	IV	V	VI	VII	Total
Gross Electrical Prod						
Gross Solar - MWh	70,598	71,635	75,229	67,358	67,651	352,471
Gross Boiler - MWh	32,663	32,856	36,887	31,663	33,470	167,539
Gross Total - MWh	**103,261**	**104,491**	**112,116**	**99,021**	**101,121**	**520,010**
Net Elec Sold - A Chan						
On-Pk - MWh	16,279	16,074	16,716	17,143	16,907	83,119
Mid-Pk - MWh	58,551	58,897	63,221	52,574	54,218	287,462
Off-Pk - MWh	19,166	19,278	20,410	17,757	17,639	94,252
Super Off - MWh	0	0	0	0	0	0
Total - MWh	**93,996**	**94,250**	**100,347**	**87,474**	**88,764**	**464,832**
Net Purch - B Chan						
On-Pk - MWh	0	2	1	0	2	6
Mid-Pk - MWh	342	318	283	476	458	1,877
Off-Pk - MWh	1,254	1,220	1,407	1,533	1,474	6,888
Super Off-Pk - MWh	617	568	665	711	696	3,258
Total - MWh	**2,214**	**2,108**	**2,356**	**2,720**	**2,631**	**12,028**
Station Load						
Station Internal - MWh	9,265	10,241	11,769	11,547	12,357	55,178
Station Ext (B Ch) - MWh	2,214	2,108	2,356	2,720	2,631	12,028
Station Total - MWh	**11,478**	**12,349**	**14,125**	**14,267**	**14,987**	**67,206**
Station Internal - % of Gross	0.1	0.1	0.1	0.1	0.1	0.1
SCE Capacity Factor						
On-Pk - %	104.0	103.0	107.0	109.0	108.0	106.0
Mid-Pk - %	66.0	66.0	71.0	67.0	62.0	67.0
Off-Pk - %	17.0	17.0	18.0	17.0	15.0	17.0
Natural Gas Use						
Boiler - KSCF	411,104	422,372	455,258	339,460	359,356	397,510
Heater - KSCF	20,048	15,476	23,512	2,118	1,080	12,447
Total - KSCF	**431,152**	**437,848**	**478,770**	**341,578**	**360,436**	**409,957**
FERC Calc (LHV)						
Solar Energy Input - MMBtu	1,186,056	1,203,316	1,317,270	939,047	990,663	1,127,270
Gas Energy Input - MMBtu	394,820	400,581	438,508	312,739	329,807	375,291
FERC Ratio	**24.97**	**24.98**	**24.98**	**24.98**	**24.98**	**24.98**

1999 ANNUAL PRODUCTION SUMMARY

Performance	III	IV	V	VI	VII	Total
Gross Electrical Prod						
Gross Solar - MWh	70,689	71,142	70,293	71,046	66,258	349,427
Gross Boiler - MWh	33,272	33,941	35,437	34,167	34,176	170,994
Gross Total - MWh	**103,961**	**105,083**	**105,730**	**105,213**	**100,434**	**520,421**
Net Elec Sold - A Chan						
On-Pk - MWh	15,953	15,885	16,195	15,719	15,651	79,403
Mid-Pk - MWh	57,303	57,433	57,910	49,274	46,581	268,500
Off-Pk - MWh	20,605	20,766	20,825	27,772	26,459	116,427
Super Off - MWh	0	0	0	0	0	0
Total - MWh	**93,860**	**94,084**	**94,930**	**92,765**	**88,691**	**464,330**
Net Purch - B Chan						
On-Pk - MWh	0	1	0	1	1	3
Mid-Pk - MWh	357	333	422	469	486	2,068
Off-Pk - MWh	1,386	1,259	1,363	1,450	1,419	6,878
Super Off-Pk - MWh	633	534	585	719	700	3,171
Total - MWh	**2,377**	**2,127**	**2,370**	**2,640**	**2,606**	**12,120**
Station Load						
Station Internal - MWh	10,101	10,999	10,800	12,448	11,743	56,091
Station Ext (B Ch) - MWh	2,377	2,127	2,370	2,640	2,606	12,120
Station Total - MWh	**12,477**	**13,126**	**13,170**	**15,088**	**14,348**	**68,210**
Station Internal - % of Gross	0.1	0.1	0.1	0.1	0.1	0.1
SCE Capacity Factor						
On-Pk - %	103.0	103.0	105.0	102.0	101.0	103.0
Mid-Pk - %	66.0	66.0	78.0	56.0	52.0	63.0
Off-Pk - %	18.0	18.0	21.0	24.0	23.0	21.0
Natural Gas Use (HHV)						
Boiler - mmBtu	426,099	446,316	447,301	374,976	374,613	413,861
Heater - mmBtu	1,980	1,415	3,585	436	518	1,587
Total - mmBtu	**428,080**	**447,731**	**450,886**	**375,412**	**375,131**	**415,448**
FERC Calc (LHV)						
Solar Input - mmBtu (HHV/1.11)	926,367	968,876	975,808	812,456	811,827	4,495,333
Gas Used - mmBtu	385,657	403,361	406,203	338,209	337,955	1,871,386
FERC Ratio (w/0.8 Boiler Eff.)	**24.98**	**24.98**	**24.98**	**24.98**	**24.98**	**24.98**

2000 ANNUAL PRODUCTION SUMMARY

Performance	III	IV	V	VI	VII	Total or Avg.
Gross Electrical Prod						
Gross Solar - MWh	65,994	63,451	73,810	68,543	64,195	335,993
Gross Boiler - MWh	30,750	30,090	36,897	33,375	32,578	163,690
Gross Total - MWh	**96,744**	**93,547**	**110,708**	**101,918**	**96,773**	**499,690**
Net Elec Sold - A Chan						
On-Pk - MWh	15,767	15,728	16,247	15,724	15,702	79,167
Mid-Pk - MWh	52,122	50,122	62,203	55,035	51,273	270,754
Off-Pk - MWh	18,944	18,089	21,039	18,937	18,815	95,824
Super Off - MWh	0	0	0	0	0	0
Total - MWh	**86,832**	**83,938**	**99,489**	**89,695**	**85,790**	**445,745**
Net Purch - B Chan						
On-Pk - MWh	2	1	1	0	0	3
Mid-Pk - MWh	452	500	369	460	476	2,257
Off-Pk - MWh	1,427	1,359	1,565	1,693	1,549	7,594
Super Off-Pk - MWh	575	561	635	721	668	3,160
Total - MWh	**2,456**	**2,421**	**2,570**	**2,874**	**2,693**	**13,014**
Station Load						
Station Internal - MWh	9,912	9,603	11,218	12,223	10,983	53,938
Station Ext (B Ch) - MWh	2,456	2,421	2,570	2,874	2,693	13,014
Station Total - MWh	**12,367**	**12,024**	**13,787**	**15,097**	**13,676**	**66,952**
Station Internal - % of Gross	10.2	10.3	10.1	12.0	11.3	10.8
SCE Capacity Factor						
On-Pk - %	103.1	102.8	106.2	102.8	102.6	103.5
Mid-Pk - %	59.7	57.2	70.5	62.2	69.2	63.8
Off-Pk - %	16.5	15.7	18.2	16.4	18.3	17.0
Natural Gas Use (HHV)						
Boiler - KSCF	386,581	391,992	455,796	364,730	355,558	1,954,658
Heater - KSCF	4,401	4,093	2,396	963	4,144	15,998
Total - KSCF	**390,983**	**396,086**	**458,193**	**365,693**	**359,702**	**1,970,656**
FERC Calc (LHV)						
Solar Input - MMBtu	859,068	863,331	998,094	798,194	794,061	4,312,748
Gas Used - MMBtu (HHV/1.11)	352,480	357,090	412,829	329,521	323,445	1,775,366
Monthly FERC Ratio	**24.71**	**24.86**	**24.86**	**24.83**	**24.58**	**24.77**

Note: HHV is the Higher Heating Value. LHV is the Lower Heating Value.

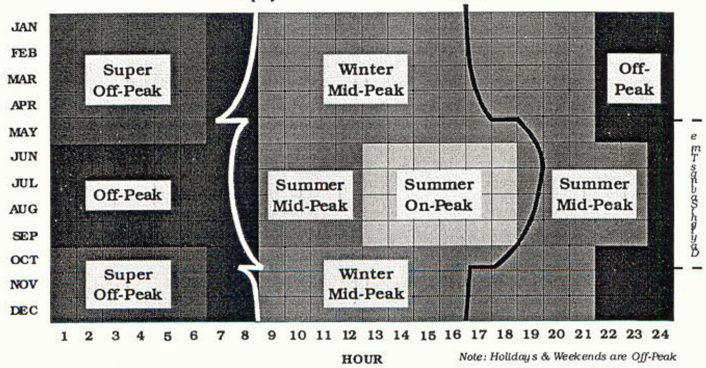
2001 ANNUAL PRODUCTION SUMMARY

Performance	III	IV	V	VI	VII	Total or Avg.
Gross Electrical Prod						
Gross Solar - MWh	69,369	64,842	71,827	67,339	64,210	337,587
Gross Boiler - MWh	34,059	30,585	33,199	31,954	31,539	161,336
Gross Total - MWh	**103,428**	**95,427**	**105,025**	**99,293**	**95,749**	**498,923**
Net Elec Sold						
On-Pk - MWh	15,777	15,650	16,101	15,477	15,507	78,512
Mid-Pk - MWh	53,732	47,472	54,704	48,406	47,188	251,501
Off-Pk - MWh	22,722	21,550	23,670	23,568	22,058	113,568
Super Off - MWh	358	351	360	0	1	1,070
Total - MWh	**92,589**	**85,023**	**94,836**	**87,451**	**84,753**	**444,651**
Net Purch						
On-Pk - MWh	0	3	2	2	1	7
Mid-Pk - MWh	459	567	473	531	498	2,528
Off-Pk - MWh	1,374	1,418	1,452	1,613	1,444	7,301
Super Off-Pk - MWh	568	589	611	691	642	3,101
Total - MWh	**2,402**	**2,576**	**2,538**	**2,834**	**2,585**	**12,934**
Station Load						
Station Internal - MWh	10,839	10,404	10,189	11,842	10,996	54,271
Station External - MWh	2,402	2,576	2,538	2,834	2,585	12,934
Station Total - MWh	**13,241**	**12,979**	**12,727**	**14,676**	**13,581**	**67,205**
Station Internal - % of Gross	10.5	10.9	9.7	11.9	11.5	10.9
SCE Capacity Factor						
On-Pk - %	104.3	103.5	106.5	102.4	102.6	103.9
Mid-Pk - %	64.3	64.7	65.8	54.6	55.5	61.0
Off-Pk - %	20.4	21.5	21.5	20.4	19.3	20.6
Natural Gas Use (HHV)						
Boiler - KSCF	416,086	387,042	417,198	351,696	340,158	1,912,180
Heater - KSCF	1,008	1,804	2,804	1,856	1,838	9,310
Total - KSCF	**417,094**	**388,846**	**420,002**	**353,552**	**341,996**	**1,921,490**
FERC Calc (LHV)						
Solar Input - MMBtu	1,152,972	1,070,922	1,172,406	976,537	942,559	5,315,395
Gas Used - MMBtu (HHV/1.11)	380,408	354,622	383,071	322,474	311,938	1,752,513
Monthly FERC Ratio	**24.81**	**24.88**	**24.63**	**24.82**	**24.87**	**24.80**

Note: HHV is the Higher Heating Value. LHV is the Lower Heating Value.

Appendix "B"

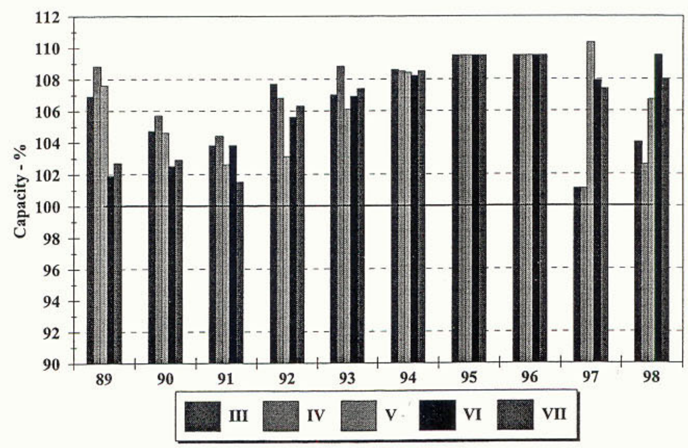
Figure 9—Southern California Edison (SCE) Time-Of-Use (TOU) Rate Periods



Capacity is defined by the nameplate rating for hourly production set forth in the power purchase agreement (PPA), multiplied by the number of hours available in a given TOU period. Therefore, 100% of on-peak capacity at the Kramer SEGS with nameplate ratings of 30 MWe and 6 "peak" hours per "peak" day requires the generation of 180 MWh multiplied by the number of peak days in a given month, normally between 19 and 23 days per month over the four-month summer peak period. As equipment capabilities make hourly net generation of approximately 34 MWe possible, the maximum theoretical percentage of peak capacity at the Kramer SEGS is approximately 113%.

Due to the critical role of the gas-fired boiler back up in assuring production levels during inclement or changing weather, the boiler must remain on-line when any threat of declining solar conditions exists. In order for this to happen, the boiler must meet minimum throughput levels which mean that boiler must be contributing between 3 to 5 MWe of the total production. If solar conditions allow for the production of approximately 34 MWe or more—the maximum production possible for the equipment—the solar contribution must be backed out by 3 to 5 MWe by defocusing Solar Collection Assemblies (SCAs) in order for the boiler to remain on-line. If and when this happens, this condition functionally equates to loss of 3 to 5 MWe of potential solar production (and revenues) and the gas credits that would have produced 25% of the lost solar generation with gas production (and revenues). Therefore, gas is not to be used if it results in dumping solar energy unless the achievement of targeted capacity cannot otherwise be met.

Figure 10—On-Peak Capacity: SEGS III-VII



Appendix "C"

Figure 4—Solar Collection Assembly (SCA) Availability: Actual & Projected, SEGS III-VII

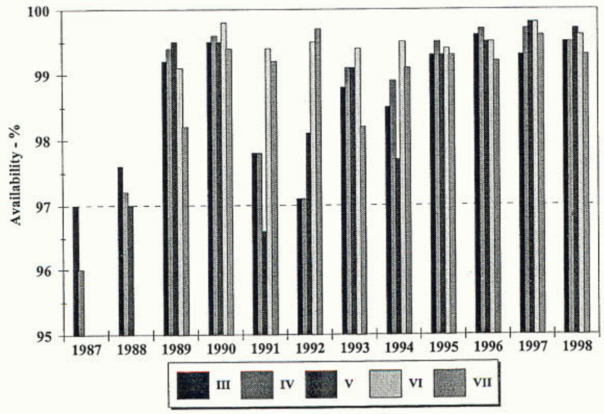
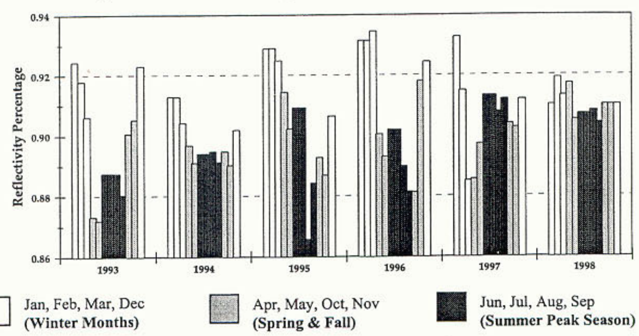


Figure 5 displays actual and targeted reflectivities for the Kramer site. Reflectivity—and the related solar—has only been monitored and gauged to the current level of accuracy since 1993. Previously, the methodology and instrumentation necessary to accomplish such a feat had not been adequately developed. KJC OC has, since that time, improved its cleaning methodology resulting in the increasing reflectivities for the summer months as depicted by the darker-shaded bars on the reflectivity graph.

Figure 5—Site Reflectivity: Actual & Targeted, SEGS III-VII



Solar Efficiency

Solar efficiency is measured in two ways at the Kramer SEGS. First is the solar field (or thermal) efficiency which is the ratio of the thermal output of the solar field vs. the incoming direct normal insolation (DNI). Second is the solar electric efficiency, which is the ratio of solar electric output vs. the incoming DNI. In both cases no corrections are taken into account for HCE and RP status, RP reflectivity, SCA availability, or forced and non-forced outages due to power block equipment.

The solar to electric efficiencies and the solar field efficiencies for SEGS VI are shown on Figure 6 for the 1997 year on a monthly basis. Solar to electric efficiencies range from 18% in the summer months to 5% in the winter. SEGS III–V typically are 1–3% lower due to the non-reheat turbine cycle. Solar field thermal efficiencies, which do not include losses from the steam cycle, range from 55% in the summer months to 20% in the winter months. SEGS III–V typically have thermal efficiencies close in value to SEGS VI and VII, and can be even higher depending on the solar field condition. Due to the North/South tracking axis of the SCAs at the Kramer site, higher efficiencies and thus more production, occur during the summer months when the demand for electricity is highest.

C.1.1 RESPONSE TO SOLARGENIX COMMENTS

First, please see the general response on page 83.

Three separate comments were received that stated that the solar capacity credit determined by this study is lower than expected. Because this concern was repeatedly raised, the analysis was carefully reviewed to identify potential causes of the deviations from the commenting parties' expectations. This is discussed below. Until additional analyses can be conducted, the relative capacity credit for solar determined in this study is not recommended for interim application in RPS bid selection, as was proposed earlier in the 12 September 2003 public workshop and in drafts of this report. New findings pertaining to the solar capacity credit calculation will be published in an addendum to this report or in reports for the remaining portions of the study.

The solar aggregate encompasses approximately 75% of the installed solar nameplate capacity in California and the vast majority of California's solar generation comes from SEGS solar facilities with gas assist, so the solar aggregate should be representative of the SEGS plants cited by Solargenix. Given that the solar data used in the analysis is taken from CaISO's PI system, it is reasonable to assume that the data is accurate. The generation data collected by the PI system is a plant's or aggregate of plants' net power generation. The data does not distinguish between the individual generators in a plant or plant aggregate, so any backup generation or energy storage in the solar aggregate is already included. Nevertheless, it would be useful to be able to verify the analysis data with a corresponding data set from the IOU or plant operators/owners.

As discussed on page 32, the variation in power generation during the top two hundred load hours of the year may reveal one of the reasons that the capacity credit is lower than the commenting parties' expectations. While the generation is very high during most of these hours, variation does exist with some significant drops.

The sensitive relationship between peak load hours, high risk hours, and maintenance scheduling was discussed at the 12 September 2003 public workshop. Although maintenance scheduling was ultimately dropped in the final Phase I analysis presented in this report, its effects on risk levels are recognized and are still being considered in the subsequent phases of the study.

The perceived low value for the capacity credit may also be caused by a discrepancy in nameplate capacities. The analysis assumed that the nominal capacity of the aggregate is the maximum power generated in the year. The information submitted by Solargenix states that the capacity factors of the cited plants sometimes exceed 100%. The value of the aggregate's capacity used in the analysis may therefore be higher than its nameplate capacity, lowering the capacity credit.

In the near term, the solar capacity credit will continue to be investigated by expanding the solar aggregate to encompass nearly all of the California's solar generation, analyzing additional years of data, and using the published nameplate capacities of the generators.

Regarding the forced outage rate values discussed in Section 3.2.2: The gas reference unit used to determine the ELCC values has a forced outage rate of 4% and a maintenance rate of 7.6%. These values were derived from Resource Data International's BaseCase database. The 10% forced outage rate with an ELCC of 100% relative to rated capacity is for a generic conventional 100 MW unit. This case is presented only for illustrative purposes. The caption of Figure 3.3 has been modified to clarify this.

C.2 Comments from Office of Ratepayer Advocates, Received 24 October 2003

ORA

Office of Ratepayer Advocates
California Public Utilities Commission

Regina A. Birdsell, Director

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October 24, 2003

Comments of the Office of Ratepayer Advocates on the Phase I report of the California Renewable Portfolio Standard Renewable Generation Integration Cost Analysis, sponsored by the California Energy Commission in support of the California Public Utility Commission's Renewable Portfolio Standard implementation.

The Office of Ratepayer Advocates (ORA) strongly supports the October 9, 2003 version of the Phase I report of the California Renewable Portfolio Standard Renewable Generation Integration Cost Analysis, with one major reservation regarding solar capacity credit, mentioned below. The general approach of the study, dividing the integration costs and benefits into three elements, capacity credit, regulation cost, and load-following cost, is logical and well defended and explained. The results of the report, although based only on one year of data, provide an excellent basis for continuing and refining this type of analysis. We agree that the Phase I results "provide some values which can be applied immediately to RPS bid selection while the methodologies are refined and finalized in the subsequent phases of the study."

Capacity Credit of Renewables

We support the use in the report of the Effective Load Carrying Capability (ELCC) method to find the capacity credit of energy resources. ORA has supported this approach for some time, and the use of the ELCC is also consistent with CPUC Decision 03-06-071 of June 19, 2003 which stated:

> " …the ELCC is a useful concept, and we may consider it when adjusting RPS program capacity payments in the future. Parties are encouraged to explore its use in future phases of this proceeding and related proceedings."[1]

[1] CPUC Decision 03-06-071, pp. 27-8.

The results for wind energy, giving ELCC values of from 22 to 26 percent of the rating for the three major wind sites, are consistent with ORA testimony in CPUC cases[2], and with several other studies[3]. However, the anomalous results of the ELCC study for solar energy, with a significantly lower capacity credit, 57 percent of rating[4], than that found in all other ELCC studies[5], which have found solar ELCC/Ratings to be over 75 percent, troubles us. It is possible the results, being based on data for only one year and just one or two sites are not statistically significant. There could also be erroneous data, or a peculiarity of the solar technology or of its rating method, or of the solar resource at the site(s), causing the relatively low correlation with utility need. The solar results should be subjected to further analysis before this solar number is used for any type of rate setting. Such continuing analysis, in addition to finding if this solar ELCC rating is accurate, may well find that changes in solar plant location, technology, or operating strategy could greatly increase solar energy's capacity value to the grid.

We do have a minor suggestion on methodology. On page 24 of the report it is asserted that "it is not possible to analytically solve [the ELCC formula]" and thus you use an iterative method to approximate the ELCC. However there is an easier method. First finding the annual sum of the system Loss of Load Expectation with and without a specific renewable (or other source) which you already do. Then, by using the Garver Approximation the ELCC can be found directly from these two numbers by multiplying the Garver constant "m" by the natural logarithm of the ratio of the LOLE with and without the energy source being analyzed.[6] The Garver constant is usually available from the computer model

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[2] ORA found, based on four years of data, that the Tehachapi and San Gorgonio wind farms had average annual ELCC/Rating values of 25 and 24 percent, respectively.

[3] Altamont Pass winds were found to have an annual ELCC/Rating of 21.3 percent based on 4 years of analysis of data from the 1980's in "Wind Energy Resource Potential and the Hourly Fit of Wind Energy to Utility Loads in Northern California", Windpower '90, D.R. Smith for PG&E, p.52.

[4] The report, pp. xi and 30-31.

[5] See, for example, a map showing solar ELCC/Rating prepared by the National Renewable Energy Laboratory, available at http://www.nrel.gov/ncpv/documents/pv_util.html

[6] "Wind Energy Resource Potential and the Hourly Fit of Wind Energy to Utility Loads in Northern California", Wind power '90, D.R. Smith for PG&E, p.51.

used to find the LOLE. If not, it can be approximated from the slope of the LOLP vs. load line near the end representing higher probabilities of failure and high loads.

Sincerely,

Scott Cauchois
Senior Manager, Electricity Resources and Pricing Branch

Cc: Don Smith, Policy Analyst, Electricity Resources and Pricing Branch

C.2.1 RESPONSE TO OFFICE OF RATEPAYER ADVOCATES COMMENTS

Please see the response to Solargenix in Section C.1.1.

C.3 Comments from California Wind Energy Association, Received 24 October 2003

California Wind Energy Association

CalWEA

October 24, 2003

Kevin Jackson
c/o California Wind Energy Collaborative
Department of Mechanical and Aeronautical Engineering
University of California, Davis
One Shields Avenue
Davis, CA 95616

Re: "California Renewables Portfolio Standard Renewable Generation Integration Cost Analysis: Phase I" – October 9, 2003, Release for Public Review

Dear Kevin,

Congratulations to you and the analysis team for your thorough, and thoroughly professional Phase I report. This report will be of tremendous value to the CEC, CPUC, and stakeholders as the California's RPS program is implemented. We are very pleased that some of the nation's foremost experts in these subject areas, on loan from U.S. DOE laboratories, were available to participate closely in this project, and that the methods received substantial advance vetting at public workshops and in electronic mail forums.

The California wind industry is particularly indebted to this effort, as this report documents, quantitatively and objectively, that the system integration costs of the state's existing wind projects are extremely modest and wind's capacity value is quite significant. We look forward to the Phase II results, but appreciate the report's statements that these values will persist under moderately increased levels of penetration.

As most of the comments we provided previously have been addressed, we are reduced to commenting on just a few aspects of the report:

1. Evaluations need to be performed for additional resources, including landfill gas, small hydro resources, the Solano County wind resource area, and for geothermal resources other than The Geysers. We presume that the non-fuel-constrained geothermal results were based on adjustments to The Geysers' data, and that this is expected to be at least somewhat representative of geothermal resources other than direct-steam resources. It would be useful if the report could comment on the applicability of the non-fuel-constrained resource results to non-Geysers geothermal resources, and ultimately to run the analysis for other geothermal resources.

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☐ **Administrative:** 14961 Ballou Circle · Westminster CA 92683 · (714) 418-1074 · Fax (714) 418-0405 · admin@calwea.org

2. On page 23, section 3.1.1, it appears that the figure "390 MW" should be "425 MW." There is also a computer glitch in calculation 3.1.

3. Though the report states that wind bidders in existing resource areas will "almost certainly" be able to improve their capacity values, given newer technologies (p. 37-38), this statement could be substantiated by running the analysis using data from an old and a new turbine at an existing site. (Newer solar technologies may also have higher capacity values.) A CalWEA member previously provided you with data that would allow for this comparison. Given that some utilities are now in the process of acquiring renewable resources, it would be useful to have some indication of the effects of new technology in advance of the Phase II report

Again, thanks to you and the other authors for all of the time and effort that you have put into these analyses, which will enormously benefit the RPS implementation process.

Sincerely,

/s/

Nancy Rader
Executive Director

C.3.1 RESPONSE TO CALIFORNIA WIND ENERGY ASSOCIATION COMMENTS

First, please see the general response on page 83.

Additional resource, region, fuel, and technology analyses will be performed in subsequent phases of the study. Although the turbine data was not used in the Phase I analyses, it will be useful during the remainder of the study and the Methods Group is grateful for its contribution.

C.4 Comments from Southern California Edison, Received 24 October 2003

Southern California Edison Co.
Comments on
California Renewables Portfolio Standard
Renewable Generation Integration Cost Analysis
Phase 1: One Year Analysis of Existing Resources
Results and Recommendations
Final Report
Dated: October 9, 2003

Introduction

Southern California Edison Co. is pleased to review the subject report and acknowledges the time and effort expended by its principle contributing parties:

- Oak Ridge National Laboratory;
- National Renewable Energy Laboratory;
- California ISO; and,
- California Wind Energy Collaborative

SCE finds numerous issues that are not dealt with in the report which raise many concerns about the validity of the results.

Discussion

With respect to imbalance costs, SCE was surprised with the result and assume you were also, given that it was so much lower than the estimates provided from other research efforts. For example, Brendan Kirby was a co-author on a joint paper delivered at a June 2003 wind conference. Table 6 from that paper summarizes the state of the art findings:

Table 6. Summary of Study Results

Study and Relative Wind Penetration	Analytic (A) or Case Study (C)	Regulation	Load Following (L) or Imbalance (I)	Reserves	Unit Commit-ment	Allocation Method M=Market, I=Incremental O=ORNL	Cost $/MWh from Studied Time Scales
Hirst PJM 0.06%-0.12%	(A)	Y	I			M	$.0.05-$0.30/MWh Regulation
Milligan IA up to 22.5%	(A)		L, I	(1)		O	(2)
UWIG / Electrotek Xcel 3.5%	(C)	Y	L, I (3)	Y	Y	I	$2.00/MWh
PacifiCorp IRP 20%	(C)		I	Y		I	$5.50/MWh
Hirst BPA 5.9%	(C)	Y	L, I		Y	O	$1.37-2.17/MWh

(1) Used 3 x standard deviation as indirect estimate of reserve requirements.
(2) Cost was not estimated in this study. Allocation of system variation (based on standard deviation) to wind ranged up to 2.5% of the wind rated capacity for load following and up to 4% for imbalance, for penetration rates up to 22.5% based on capacity.
(3) Imbalance energy costs determined from Unit Commitment production cost simulations

SCE also noted the result shown in a paper presented by researchers in Denmark in 2001 at http://www.windpower.org/en/tour/wres/dkmap.htm
In that paper, the payment for "realtime imbalance power" is listed at DKK 65 million or DKK 0.02/kWh from 3372 GWh of wind. At 6.7 DKK/dollar, this is 2.9 mills/kWh. I note that it is unclear if this is the total system cost impact for this IOU due to wind power or a subset of the total cost picture.

SCE assumes that, given that the value shown in the report was almost 15 times smaller than this 2.9 mill value and well below any value presented in Table 6 for nontrivial penetration levels, it should be the cause for concern.

How has this inconsistency been addressed and confirmed the robustness of the result? If the 0.2 mills value is just the regulation component, is the report doing a disservice to ratepayers by ignoring 93% of the potential total imbalance costs associated with intermittent resources relative to non-intermittent resources?

With respect to ELCC, SCE noted that the ELCC for solar was 39% of nameplate (subsequently revised to 56.6%) and those for geothermal and biomass were much larger. Frankly, this result surprises us unless the solar data you used were based on a pure solar project (e.g., PV) and not a gas-assisted solar project. If it were supposed to be reflective of the latter, it fails a fundamental logic test. SCE's solar thermal units have over the past 10 years consistently realized close to 100% of their maximum capacity bonus payments. These payments are directly related to the plants' capacity factor in the summer on peak hours and reflect performance at or close to 100% capacity factor during summer onpeak hours. Insofar as your ELCC is supposed to reflect top load hours and insofar as most of Edison's top load hours occur in the summer on peak hours, then a 39% result for gas-assisted solar is questionable.

In a prior discussion, SCE suggested that your ELCC calculations be done for each time of delivery period ("TOD") separately and then aggregated in proportion to the value associated with each such TOD period (or based on the % of top load hours in that TOD period). I also suggested that August and September needed to be differentiated from June and July, given that we have far more high load hours in August and September than in June and July. If you have not done this, then your solar number is too low and your wind number likely too high.

SCEs other question is if the data used for your calculations were aggregated data--that is, if all projects with a given fuel were combined together to produce the generation profile. I assume that you used aggregate data, for, if you did not, I would expect that you would have presented your results as ranges of value rather than a single value, reflecting likely local variations. If you did use aggregate data, I think it appropriate to keep in mind the goal here--to assist in a bid evaluation process in which we have to distinguish between adding a geothermal project or a wind project. In this context, I believe that the ELCC calculation must be TOD-weighted AND that it must reflect the output of a specific geothermal project or of a specific wind project, not the aggregate output of many wind projects or of many geothermal projects. Are you able to generate project-specific ELCC value ranges?

Finally, SCE has attempted on numerous occasions to validate the input data with the representatives of the CaISO. CaISO has been entirely unresponsive to SCEs repeated requests. SCE questions the validity of the input data since during the workshop in Sacramento on September 12, 2003, it was stated that the Geysers geothermal plants were utilized for the representative geothermal production profile; that none of the LUZ-SEGS facilities were utilized for the solar generation profile, and that 1200 MW of wind were utilized for the wind profiles, but that they were unable to specify which plants in which resource areas were included (SCE alone has over 1,000 MW of wind). The Geysers production profile is entirely unrepresentative for SCE's geothermal plants. The LUZ-SEGS plants are more representative of the likely future solar generation than any other solar facility. And it is unclear if the wind facilities that were utilized were in fact representative of SCE wind resource areas. As a result, one cannot be assured that the results are representative for the purpose that they are being prepared, specifically, to produce cost adders which can be added to a project's bid price during the bid selection process (see page xi).

C.4.1 RESPONSE TO SOUTHERN CALIFORNIA EDISON COMMENTS

There are several reasons that the regulation cost results of previous studies are larger than those found in the Phase I study. The most important reason is that the Phase I study specifically distinguished regulation. The other studies valued regulation, energy imbalance, and forecasting error together. The ancillary service costs calculated in the previous studies were dominated by forecasting error costs. Specifically:

- PJM: The $0.05/MW-hr to $0.30/MW-hr regulation cost is in line with the $0.08/MW-hr procured and $0.17/MW-hr total found in the Phase I analysis.
- Xcel Energy: There was no hourly market available in the Xcel study. This, coupled with the unique generation mix, resulted in a large day-ahead forecasting error penalty that dominated the calculated cost.
- Pacificorp: Pacificorp did not analyze regulation costs and assumed they were not significant.
- BPA: Like Xcel, forecasting error accounts for most of the calculated ancillary service costs.

California's market structure, with hourly as well as day-ahead markets, provides an opportunity to rebalance the system just prior to real-time. This was not available in the midwestern markets modeled above. The sheer size of California's system also reduces the regulation impacts compared to the smaller systems above. Furthermore, forecasting errors are specifically treated separately in this study. Results from PJM, which also has well developed energy markets, are similar to those found in the Phase I study.

Please see the response to Solargenix in Section C.1.1 regarding the solar ELCC value.

Regarding the use of time of delivery periods: The ELCC approach implicitly identifies the hours when reliability is a concern. This corresponds to peak periods that span across months. The ELCC approach does not lend itself to monthly analysis because there are many times that LOLP is insignificant. Therefore, any generator, renewable or not, would be unable to increase reliability during these periods.

Please see the general response on page 83 regarding the aggregation of data and the analysis of specific generation project attributes in the later phases of the study.

Regarding the composition of the data aggregates: Any future aggregate used to represent all of California's geothermal generation will be expanded to encompass nearly all of the state's installed geothermal capacity. The solar aggregate captures 75% of California's installed solar capacity and therefore necessarily includes Luz SEGS facilities. The total wind aggregate, as described in Section 2.1.7, includes 70% of California's installed wind nameplate capacity and therefore necessarily includes a large representation of wind plants from SCE's service territory. The Phase I study also used regional aggregates for Tehachapi and San Gorgonio.

C.5 Comments from Pacific Gas and Electric Company, Received 24 October 2003

STATE OF CALIFORNIA ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION

Phase I: Findings and Results of Costs of Integrating Renewables
Implementation of Renewables Portfolio Standard

Docket No. 03-RPS-1078
RPS Proceeding

Comments of Pacific Gas and Electric on Phase I of the California Renewables Portfolio Standard Renewable Generation Integration Cost Study.

Submitted October 23, 2003

Pacific Gas and Electric (PG&E) appreciates the opportunity to comment on the Methods Group's Phase I report discussing renewable generation integration costs in the California Independent System Operator's (CAISO) control area. PG&E understands that the work of the Methods Group will be continuing into 2004 and endorses the refinements proposed for the analysis as the study continues into Phase II. In particular, the following items seem relevant to increasing the robustness of the analysis and end user's confidence in the results:

- Increased Penetration
- Different Technologies
- Siting
- Disaggregated Data
- Simplified methods for Capacity Credit

Regulation and Load Following Analysis

PG&E appreciates the Methods Group concern over the need for higher resolution data in order to attain more reliable results. Specifically, the researchers note that the data should be saved at a higher resolution than the current system. While the report does not discuss what the optimum resolution would be, it would be useful to understand the feasibility of this suggestions along with any estimate of costs that might be incurred in order to modify the data storage defaults currently in place. As a practical matter, the Methods Group should explore what level of precision is necessary, and what level of precision is physically feasible given the data storage defaults in place.

The most striking result of the Phase I study is the small magnitude of the results and in particular, when compared to similar studies looking at integration costs. The report notes that the regulation costs are relatively small, and even fall below the data error range. The authors note that it is difficult to have confidence in the precision of these small numbers. Given the reportedly large magnitude of the errors, it would be helpful for the report to explicitly state the 90%, 95%, 99%, confidence intervals to give the readers some notion of how wide the true values might be. Perhaps this wide range helps explain why these results are in fact not statistically different from those of the other reports discussed in these comments.

The report frequently notes the impact of a perceived scheduling bias. PG&E expects that the final method should properly account for the regulation cost of this bias; that is to the extent this bias is predictable, or its persistence is predictable, this should be accounted for in a way that does not in turn bias the assignment of integration costs to renewable generators.

Although the report's preliminary results demonstrate minimal regulation and load following costs, PG&E notes that results are driven by 2002 data, and therefore would PG&E prefer there be more assurance that the methodology adopted will produce results that are robust to different, but likely supply-demand scenarios. In particular, different penetration levels of intermittent resources, different levels of available spot capacity, availability of source fuel (e.g., biomass, geothermal steam), should affect the results. We should be able to see how the results would respond to these scenarios. Additionally, we would hope that the methodology would be able to be updated frequently so that the results remain relevant.

Phase I Study Results

The California Public Utilities Commission ordered that the IOUs utilize the results of the integration study in Decision 03-06-071. At this time, PG&E understands that even in the interim, while the methodology is being finalized, the results presented in Phase I integration study will be utilized to rank bids in the least cost and best fit analysis.[1] PG&E believes it is important that the study results reflect a realistic cost to integrate intermittent resources in order select the best renewable resources. Also, stakeholders in California's RPS should have confidence that the integration study results are truly

[1] Decision 03-06-071, pp. 32, "Second Ranking: Bids are re-ordered based on integration and transmission costs (1) CEC Integration Study working group methods are used to determine total integration costs for each short-listed contract; a. The results of Phase 1 of the CEC integration study will reveal the integration impacts of present generation in specified areas. These results can act as a proxy for the integration effects of adding new resources in those same areas, if Phase 2 results are not available prior to the first RPS solicitation, as discussed in TURN / SDG&E Joint Principles."

representative. PG&E does yet not have confidence that the results presented in this Phase I report are indeed representative of the integration cost of renewables but does feel that the analysis is moving at the right pace and in the right direction. PG&E would like to reiterate that it supports the process and the researchers that are working to develop a methodology that will provide a representative evaluation of the cost.

To get some perspective on the Phase I results, PG&E examined a few other contemporary studies that are evaluating integration costs for intermittent generation. The three example studies we investigated and a brief summary of the results are presented below:

1) *Characterizing the Impact of Significant Wind Generation Facilities on Bulk Power System Operations Planning,* Xcel Energy – North Case Study; Prepared for The Utility Wind Interest Group, May 2003

   Four cost categories were assessed:
   1) Forecast Inaccuracy for day-ahead scheduling
   2) Additional Load following reserves
   3) Intra-hour load following "energy component"
   4) Additional Regulation reserves

   The Report notes: "Summing the cost impact results for the four components assessed using the distribution forecast error range of +-50%, the impact of integrating NSP's existing 280 MW wind plant is found to be approximately $1.85 / MWh of wind generation".

2) *Integrating Wind Energy with the BPA Power System*: Preliminary Study, September 2002, Eric Hirst, Oak Ridge, Tennessee, prepared for Power Business Line, Bonneville Power Administration.

   From Conclusion, page 35, "The cost to integrate wind with the BPA power system, including adjustments for DA forecast errors and RT regulation and load following requirements, is likely to be well under $5/MWh of wind output for 1000 MW of wind capacity."

3) *We Energies Energy System Operation Impacts of Wind Generation Integration Stud,* prepared by Electrotek Concepts, September 2003

   We Energies is located in Milwaukee, Wisconsin and the state of Wisconsin has mandated utilities within the state incorporate renewable generation equal to 2.2% of their total portfolio by 2011. We Energies has an internal goal of 5% by 2005.

> The Wisconsin PUC is encouraging renewable generation of 5,000 MW to 10,000 MW within the next 20 to 30 years.
>
> The study objective was to calculate the ancillary services cost impact to We Energies (WE) to integrate bulk wind generation into WE's project year 2012 system. The study is performed for four different total rate wind plan capacities 250 MW, 500 MW, 1000 MW, and 2000 MW.
>
> The cost impact is first calculated for the worst-case scenario of wind considered in isolation from the load. A more realistic evaluation is then made by considering the impact on the aggregate uncertainty of the load and wind. Tables 11 and 12 on pages 30 and 31 present a range of results depending on the penetration and confidence levels of the allocate reserve covering forecast errors. The results, presented on page 35, show that for the realistic evaluation, with a 95% confidence level under forecast uncertainty, the total ancillary service cost ranges from $1.90 / MWh to $2.92 / MWh .

While each of these studies have specific qualifications on their data, their results, or have proposals for continuing refinement, it appears the contemporary integration costs studies indicate a trend much more significant that that reported in the California's RSP Phase I integration study. PG&E feels it would be a prudent for the Methods Group to explore at a minimum, a discussion of how their methodology differs from some of the other work that is being done in this area. This discussion or a direct comparison utilizing CAISO data in an alternative methodology would provide perspective in the conclusions that are drawn from the methodologies that are being employed in the Phase I study.

PG&E would like to encourage California Energy Commission (CEC) and California Public Utilities Commission (CPUC) Collaborative Staff to consider not only the results of the Method Group's Method 1 analysis, but also, to consider the results of the Method 2 approach discussed in the April 23 report when those results become available. The two methodologies are compared on page 58 of the Phase I report and PG&E encourages pursuing this comparison, including comparison of results, and potentially comparing similarly situated models that are being developed in other parts of the US and Canada, as appropriate.

Capacity Credit

The study indicates that for intermittent generators the Effective Load Carrying Capacity (ELCC) was calculated as a percent of maximum capacity attained over the year instead of the actual installed total nameplate capacity. This approach was taken in order to take into account the generating capacity no longer available due to some wind plants being inoperable due to lack of maintenance.

PG&E believes that simply using maximum capacity understates the amount of intermittent capacity that is in good working order. Using the maximum capacity does not take into consideration wind turbines that are available, but not operating because they are not oriented in the direction of the wind or are temporally out due to forced outage (but not in complete disrepair). PG&E recommends using total installed capacity less capacity amounts that are truly inoperable as the basis for calculating the ELCC for wind generators.

PG&E also believes the capacity credit value of baseload renewable resources such as biomass and geothermal relative to a gas plant are slightly higher than expected. This may be caused by the use of aggregated data. PG&E understands that the Phase II study will examine disaggregated renewable data to determine the individual ELCC values and that may make these results more representative.

PG&E also concurs with the Methods Group's view that for biomass and geothermal generators, it is important to ascertain the availability of the expected fuel supply over the life of the contract.

C.5.1 RESPONSE TO PACIFIC GAS AND ELECTRIC COMPANY COMMENTS

CaISO's PI system receives data at high resolutions, but saves it with a lossy compression scheme. Compression can be selectively tuned or turned off in different data streams, but the increased cost in storage is not yet understood. This is being investigated further.

The scheduling bias does not incur a regulation cost, but has an effect on load following costs. This will be considered in the future study of the impact of renewables on indirect load following costs.

Penetration and fuel availability will be considered along with generator technologies and siting in the subsequent phases of the project. As proffered, the final methodologies will be periodically updated with findings based on recent data.

Please see the response in Section C.4.1 regarding the relatively high costs determined from previous studies. Regarding the case of We Energies, forecast error dominated the calculated cost.

The Method 2 analysis is near completion and its final methodology and results will be compared with the Method 1 methodology and results detailed in this report. The findings will be published in an addendum to this report.

Regarding the use of installed capacity instead of the maximum power output on the year: As discussed above in Section C.1.1, the effect of using the nameplate capacity instead of the maximum power output is being investigated.